The Los Angeles 100% Renewable Energy Study

Chapter 6. Renewable Energy Investments and Operations

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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Chapter 6. Renewable Energy Investments and Operations

March 2021

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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** (this chapter) 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** 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 economic 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

The LA100 study identifies and evaluates pathways that achieve a 100% renewable electricity supply for the city of Los Angeles while maintaining acceptable reliability for both the grid and end users. This chapter focuses on the bulk power system—the large-scale generation and transmission infrastructure responsible for producing and delivering to the load centers the majority of electricity ultimately consumed by end users. Through simulation and analysis of the four core LA100 scenarios and associated sensitivities, we evaluate how the bulk power system could evolve to achieve a 100% renewable or clean electricity supply. We focus on addressing the following questions: what are the options for investments in generation, storage, and transmission that would achieve a 100% renewable energy target? How do the costs compare, and how do we know these systems would be reliable?

How can the target be met? Technology pathways to achieving 100%:

1. **Due to costs and LA's access to high-quality resources, wind and solar resources are responsible for providing the majority of energy required to meet load** irrespective of the broader set of options leveraged to achieve a 100% renewable power system. Across the scenarios analyzed, wind and solar account for 69%–87% of total energy generation by 2045. Figure 1 illustrates the progression of the system from 2020 through 2045 in the High Load Electrification and Stress Load Electrification scenarios**.**

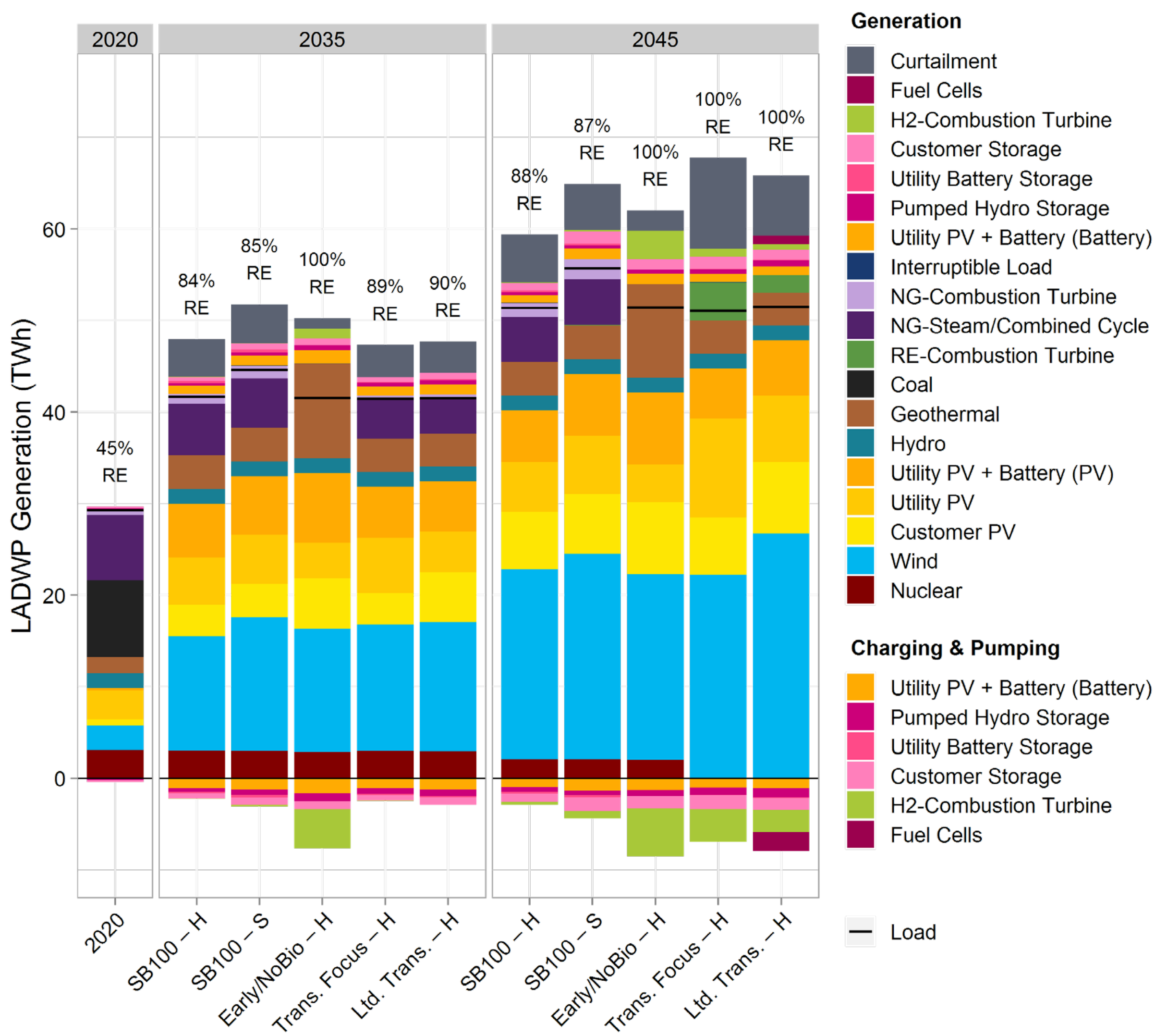

Figure 1. Annual generation mix for all High and Stress load scenarios

The percent RE refers to percent of generation that is carbon neutral (renewable and nuclear). Negative values indicate the amount of electricity consumed by the plants (e.g., to charge a battery, pump hydro, or produce hydrogen fuel). Load (solid line) is customer electricity consumption exclusive of charging. Curtailment includes available energy that is curtailed to provide reserves.

2. **Diurnal storage resources (resources with storage durations of less than 12 hours) increase the utilization of wind and solar** assets by shifting surplus energy from mid-day to evening, nighttime, and morning hours. However, due to periods of low renewable resources, diurnal storage assets combined with wind and solar generation are insufficient (at reasonable cost) to achieve a reliable, 100% renewable electricity supply.

3. **New in-basin[1] renewable firm capacity—resources that use renewably produced and storable fuels,[2] can come online within minutes, and can run for hours to days—is a key element of maintaining reliability** at least cost given the assumed retirement of natural gas generators, existing transmission constraints, and challenges in upgrading existing or developing new transmission. Figure 2 illustrates the evolution of the capacity mix over time.

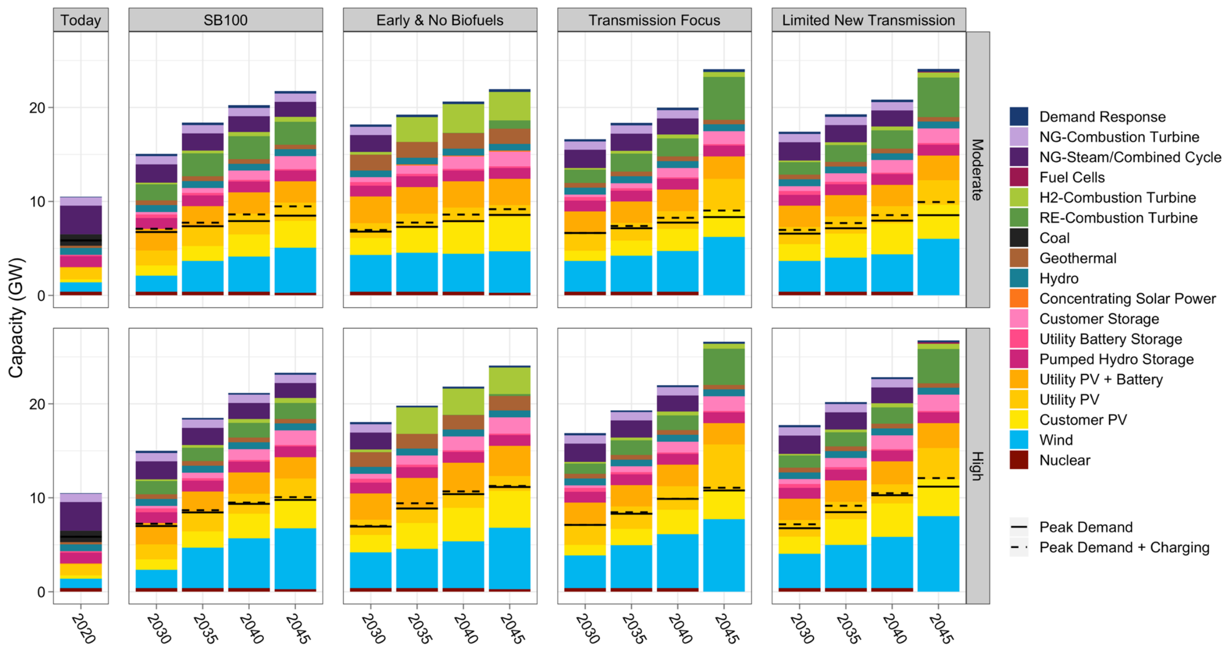

Figure 2. Capacity mix over time

Top row shows Moderate load projections for each scenario; bottom row shows High load scenarios (the Stress load scenario is not shown).

Utility PV + battery assumes co-located solar and storage with shared loosely DC-coupled inverter capacity. Capacity represented is the capacity of the inverter (i.e., the maximum output). The size of the solar relative to the battery is chosen by the model, but typically is 2:1 (e.g., 10 MW PV + battery has a 10 MW solar array with 5 MW of battery storage).

4. **Achieving a 100% renewable or clean power system requires rapid and sustained deployment of variable generation (wind and solar), diurnal storage, and firm capacity technologies**. Table 1 compares average annual growth for key technologies in the High load scenarios to the maximum capacity added within a given year by LADWP over the 2015–2020 period. Across scenarios, the average annual deployment for combined wind, solar, and batteries ranges from ~470 to 730 MW/yr over the study

[1] In this report, we use in-basin and out-of-basin to broadly refer to locations within or outside the Los Angeles B Basin. This distinction in location has implications for cost and reliability.

[2] Firm capacity represents generation that can be relied on during periods of system stress. This typically means it can serve load during periods of high demand, such as hot summer afternoons. Renewable firm capacity technologies explored in the LA100 study include fuel cells and combustion turbines that use any type of renewable fuel, including biofuel, biogas, hydrogen, and other hydrogen carriers. Hydrogen-fueled generators, including combustion turbines and fuel cells, are assumed to provide long-duration storage with LADWP self-producing hydrogen (or hydrogen carrying) fuels.

period (2021–2045), representing a substantial acceleration of procurement of new resources.

Table 1. Comparison of Technology Growth Rates by Scenario and Technology

	Maximum Annual Growth	Average Annual Growth Rate for High Load Scenarios (MW/yr)							
	Today	SB100		Early & No Biofuels		Transmission Focus		Limited New Transmission	
	2015–2020	2021–2035	2036–2045	2021–2035	2036–2045	2021–2035	2036–2045	2021–2035	2036–2045
Solar PV	~650 (2017)	290	190	400	150	320	410	350	330
Wind	0 (~100 2010–2020)	270	230	260	250	280	340	290	360
Batteries	~20 (2018)	130	100	200	80	130	100	130	100
Renewable Combustion Turbines/ Seasonal Storage	0	110	50	190	20	120	260	120	250

5. **LADWP's unique alternating-current (AC) and direct-current (DC) transmission infrastructure (existing and planned upgrades) enables the utility to access the high-quality and abundant renewable resources outside of the LA Basin and bring energy from those resources to the city**. Across all scenarios explored, out-of-basin generation resources produce the majority of electricity used to meet load (74% to 89% of total energy generation by 2045), consistent with today. As electrification significantly increases LA's demand for electricity, the total energy generated from out-of-basin sources is expected to increase to almost double the 2020 value, while the total transmission capacity into the basin is projected to increase little by 2045 in all but the Transmission Focus scenario. Reliability is maintained by making strategic upgrades to in-basin transmission assets, siting new out-of-basin resources diversely across separate corridors, developing new in-basin firm capacity resources, and demand response. This allows LADWP to operate its transmission network more flexibly and minimizes the risk presented by a failure of any transmission line.

6. **Although in-basin solar generation has the advantage of being more resilient to transmission congestion and outages, most LADWP-procured solar in the LA100 study is built outside of the LA Basin due to lower costs and the ability of existing and new transmission to support of out-of-basin resources.** All scenarios assume that customers adopt 2.8–3.9 GW of rooftop solar by 2045 (see Chapter 4 for details). Although technically eligible locations within the city for ground-mount and other utility-scale solar could support an additional 4.8 GW of solar photovoltaics (PV) at a levelized cost of less than $100/MWh, the LA100 scenarios build only a fraction of this potential due to the overall lower costs and higher performance of out-of-basin solar resources. Nevertheless, these locations could serve as alternative siting for in-basin generation

should customer-adopted solar not materialize or if LADWP chooses to site solar locally for other reasons.

7. **The Early & No Biofuels – High scenario generates 98% carbon-free electricity by 2030.** Even though the 100% target is almost met, significant new capacity is added between 2030 and 2035, primarily to replace retiring natural gas plants with a portfolio of technologies that can meet the final 2% of energy needs that had previously been served by natural gas.

What are the costs of achieving the 100% target?

The LA100 study estimates the cumulative costs for each scenario (2021–2035 and 2021–2045) associated with bulk system generation and transmission investment and operations, customer-sited solar PV installations, and distribution system upgrades required to accommodate load growth and distributed energy resources. Importantly, these cumulative costs do not include the cost of serving debt on any assets installed prior to 2021, future costs of distribution system operation and maintenance (O&M), or costs of energy efficiency and demand response programs.[3] Although these costs estimates represent a only portion of the total cost of meeting load, they are not costs additional to a business-as-usual scenario—rather they purely represent the total costs of the components of the bulk and distribution system investment and operation noted above.

1. **The estimated cumulative costs[4] of operating the power system and achieving the 100% target across the suite of scenarios explored range from $57 billion to $87 billion (2019$) depending on the scenario and load projection.** Figure 3 summarizes the range in costs, organized by load group (all scenarios within a load group serve equivalent customer demand). Annual costs, when normalized by annual generation, equate to average costs of $68–$106 per MWh of generation across scenarios by 2045. Costs increase over time across all scenarios due to the accumulation of costs of procured capacity and generation (and the associated debt or PPA payments), increasing load, and increased stringency of the renewable energy targets (Figure 4). Crucially, these annual per MWh costs are a measure of the evolution of average costs of generation, and do *not* represent the *marginal* or *incremental* cost of achieving a 100% renewable system. Rather, they explicitly represent the revenue requirement (per unit of generation) to cover the annualized costs associated with the accumulated debt service on capital investment, PPA obligations, and the annual O&M costs of operating the system. Incremental costs are discussed further in the main body of this chapter.

[3] Although this chapter focuses on the bulk system analysis, the distribution upgrade and distributed energy resources costs are included here.
[4] The costs presented are adjusted for inflation and are therefore presented in "real" terms (constant 2019$), but they are not present values—they are not discounted and therefore do not account for the time value of money. Rather, they represent the sum of the estimated cash-flow (including financing costs) from 2021 to 2045. Debt service on any capital investments that continues beyond the 2045 study end-date is not included in these cumulative sums.

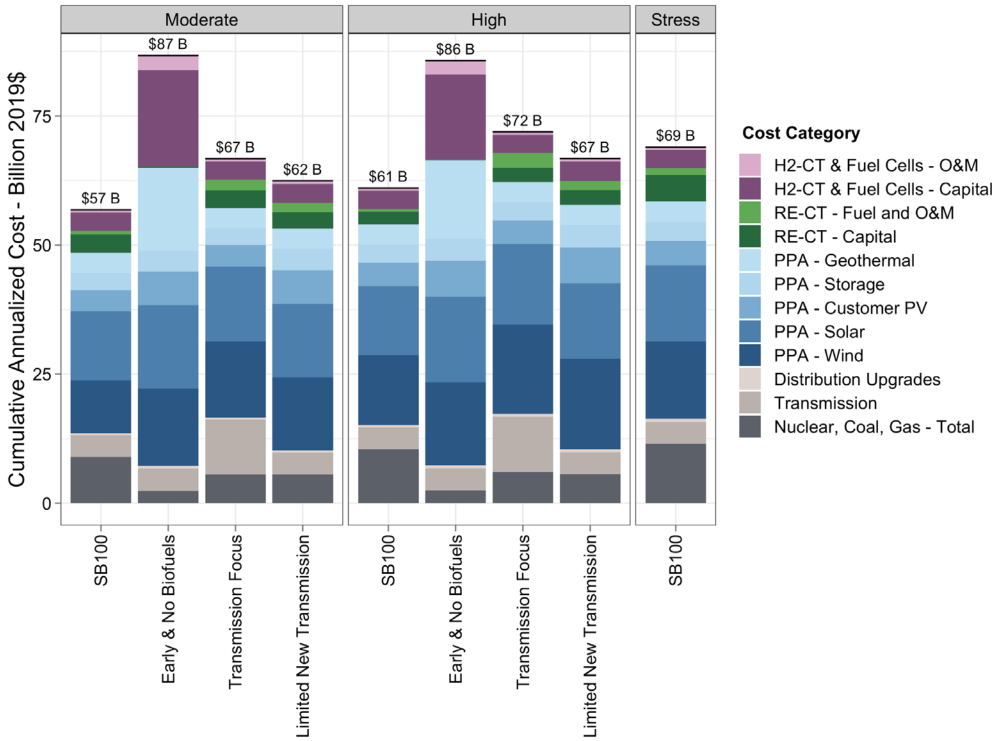

Figure 3. Cumulative annualized system costs incurred from 2021–2045 by scenario, load level, and cost type

Costs shown include bulk power system investment and operations costs and customer rooftop solar installation costs, but do not include debt payments on assets installed prior to 2021 or normal maintenance of the distribution system.

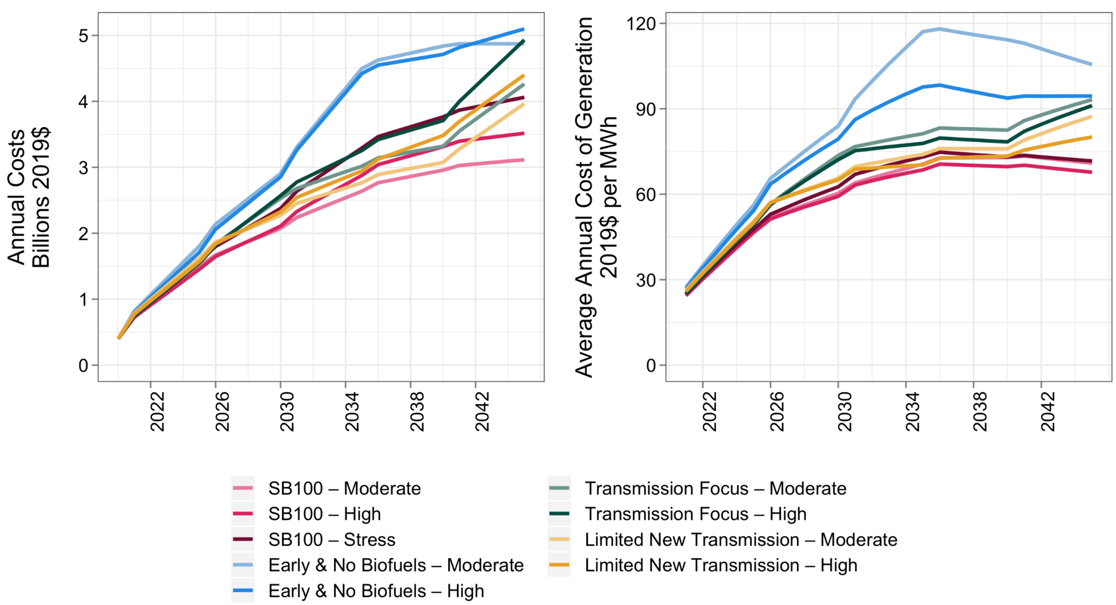

Figure 4. Annual and average annual costs of generation over time

Annual costs (left) represent the total costs observed in a given year (operations, PPA payments, annualized capital costs from LA100 resources installed in current and earlier years). Average annual costs of generation (right) normalize the annual costs over annual generation.

2. **The cost of achieving the 100% target is highly dependent on A) what technologies are assumed to qualify as "renewable," B) the availability of financial compliance mechanisms such as renewable electricity certificates, C) how quickly the target is achieved, and D) the evolution of load**. Each of these points is elaborated below.
    A. **The eligibility of technologies has a significant impact on costs.** One of the largest drivers of the cost difference of Early & No Biofuels compared to the other scenarios is the exclusion of biofuels, which is currently the only storable renewable fuel that can be purchased in sufficient quantities to serve as firm capacity. Because of this exclusion, the Early & No Biofuels scenario meets firm capacity with a higher-cost solution: increased out-of-basin geothermal capacity coupled with in-basin hydrogen combustion turbine capacity. In the case of the Early & No Biofuels – High scenario, we estimate that treating biofuels as eligible could reduce cumulative costs through 2045 by ~21%, while substantially reducing the risk of relying on less mature technologies, such as hydrogen production, storage, and use in fuel cells or combustion turbines.
    B. **Similarly, the eligibility of alternative compliance mechanisms, such as renewable electricity certificates (RECs), is an option to further mitigate the cost and uncertainty of meeting the 100% target.** RECs effectively allow an ineligible technology (primarily natural-gas generation) to contribute to the generation mix if offset with a purchased certificate. In the SB100 scenario, we estimate that disallowing the use of RECs in the year 2045 would increase cumulative costs by ~2.5% in 2045, rising to ~18% when including cumulative costs over the financial lifetime (2074) of the new investments.
    C. **The speed of the clean energy transition also impacts costs, though less so than technology eligibility.** The speed of the transition to a 100% power system impacts costs in two ways. First, costs for renewable technologies are expected to decline through 2045, so installing these technologies by 2035 comes at a higher cost compared to closer to 2045. For example, the study's cost assumptions for battery storage decline around 20% between 2035 and 2045. Second, LADWP must incur those costs earlier, which results in more costs accumulated more quickly. We estimate that extending the compliance target to 2045, assuming the use of unbundled RECs for up to 10% of compliance through 2044, would reduce cumulative costs by ~17% through 2045.
    D. **Modernizing load through increased energy efficiency and load flexibility helps mitigate the costs of achieving a 100% system.** Comparing the SB100 – High scenario to the SB100 – Stress scenario, the latter of which includes identical levels of electrification, but greater annual load (8.5% higher) and peak load (17% higher) due to lower levels of efficiency and demand response, shows that the efficiency and demand response assumed under the High scenario reduces cumulative costs by 13% through 2045.
3. **Wind, solar, and battery storage are near-term, no-regrets options to achieve a significant fraction of renewable energy generation**. The LA100 scenarios show similar cost increases through approximately 80%–90% renewable energy. Beyond 90%, the costs are highly dependent on technology choices, which vary in their maturity today.

To maintain optionality for a 100% renewable electricity system and to reduce the cost of serving demand in the hours with the lowest wind and solar availability, possibilities include:

- Fuel flexibility to serve as backup for emergencies or as a hedge against uncertainty related to prices or market availability of fuels
- Automated demand response, such as through investments in information and communication technologies and customer education and outreach, to reduce the need for new supply capacity
- Power market participation to enable imports of low-cost renewable electricity for storage (and increase revenue through sales)
- Advanced transmission technologies, such as flexible AC transmission systems, to make more effective use of existing transmission capacity.

How is reliability maintained in a 100% renewable power system?

1. **All modeled scenarios achieve the 100% renewable or clean energy targets while maintaining resource adequacy**. While wind and solar technologies provide a large fraction of the energy needs, all scenarios rely heavily on diurnal storage (storage with less than 12 hours of capacity), demand response, and renewably fueled generators to provide operational flexibility and operating reserves. In addition, renewably fueled generators capable of operating for extended periods over multiple sequential days ensure load balancing on consecutive days or weeks with low wind and solar resource availability.

2. **The role of energy storage is particularly important in all scenarios.** Storage technologies such as pumped hydro storage and batteries address the majority of the daily mismatch of supply and demand. Seasonal storage (e.g., hydrogen technologies) is relied on primarily to address seasonal mismatches in supply and demand, and to replace various services currently provided by in-basin natural gas generators that are expected to retire. Storage is also an important source of operating reserves. The use of storage introduces new complications in guaranteeing that the system can respond, including careful state-of-charge monitoring and ensuring replacement reserve capacity is available during extended outage events.

3. **Maintaining sufficient in-basin firm capacity resources allows the future systems to continue uninterrupted operation during infrequent but impactful long-duration transmission outages.** Analysis of the performance of the 2045 Early & No Biofuels – High system under 215 long-duration transmission outage events demonstrated that the ability to increase generation from in-basin firm capacity allows load to be met under the large majority of outages explored, including a majority of the more extreme (Critical N-1-1) outages.

4. **Maintaining reliability will require new methods and approaches to planning and operating the power system.** Increased reliance on wind, solar, and storage will require improved ability of LADWP to forecast resource supply, demand, and the overall state of the system. This includes monitoring either directly (or indirectly) distributed resources and creating the proper signals and incentives to optimally utilize customer-sited storage, controlled EV charging, and demand response. New software, controls, communication,

and monitoring will be required across the entire system to better coordinate the operation of generation, transmission, and distribution resources across multiple time scales. This will be particularly important to maximize the use of wind and solar delivered from outside the LA Basin and to decrease the use of higher-cost in-basin dispatchable generation assets traditionally used to provide reliability services.

Important Caveats

1. **The Early & No Biofuels scenario assumes the ability to quickly scale up hydrogen infrastructure**. While hydrogen technologies have been deployed at smaller scale to support oil refineries and ammonia production, they have not been deployed at scales needed for a large power system, in particular the infrastructure needed to transport and store the hydrogen fuel in sufficient quantities needed for reliability.
2. **Because of the unique challenges in building new transmission infrastructure, the costs and feasibility of transmission upgrades are among the most uncertain inputs to modeling of pathways to 100% renewable energy**. Simplifications were made to represent transmission infrastructure and upgrade costs in the capacity expansion and production cost modeling stages. We assume that transmission upgrades include adding capabilities to utilize existing and new capacity more fully, meaning they can be operated closer to their thermal limits. These capabilities may include dynamic line ratings, flexible AC transmission, and use of fast responding inverter-based resources and demand response to manage contingency events. The costs of some of these capabilities are uncertain, and not fully captured in the study.
3. **The evolution of the power system outside of LADWP could impact LADWP's opportunities**. For example, faster decarbonization across the West could affect locations for out-of-basin renewable generation and transmission, as well as increase periods of surplus generation and transmission congestion. Coordinated planning and market participation could also present new opportunities to reduce costs of the 100% renewable transition.
4. **The potential role of the customer has not been fully explored.** The LA100 study assumes significant changes to the traditional role of the customer, with loads (particularly EV charging) providing an important source of flexible load and demand response, including provision of operating reserves in response to contingency events. However, most of the demand for electricity is still assumed to be inflexible. Changes to utility tariffs, communication technologies, and networked end-use devices could allow customers to dramatically change energy usage—at a scale not yet tested—to offset in-basin firm capacity and transmission upgrades.
5. **Climate change could impact the ability of LADWP to maintain resource adequacy.** The study assumes rising temperatures as part of the projections for customer electricity demand. The study also evaluates the ability of LADWP to serve load during transmission outages, which may become more frequent due to wildfires. However, the study does not consider many other potential impacts of a changing climate, including changes in wind patterns, how increased temperatures could accelerate degradation of transmission equipment and result in more frequent outages, or the impact of fires on output from solar capacity.

6. **The study does not fully assess the feasibility of the accelerated deployment; in particular, the study does not evaluate the availability of manufacturing supply chains and labor forces or detailed construction schedules for the resources identified in each scenario.** However, despite the levels of deployment observed representing a large acceleration in procurement for LADWP, these changes remain small in the context of existing and expected growth in national and international renewable energy and storage industries. As a result, we expect these rates to be able to be supported over a 25-year planning horizon. In addition, leveraging some limited flexibility in the timing of retirement of existing and addition of new resources could alleviate many risks associated with the rapid construction and integration of resources along the identified investment pathways.

1 Methodology and Assumptions

1.1 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 5 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.

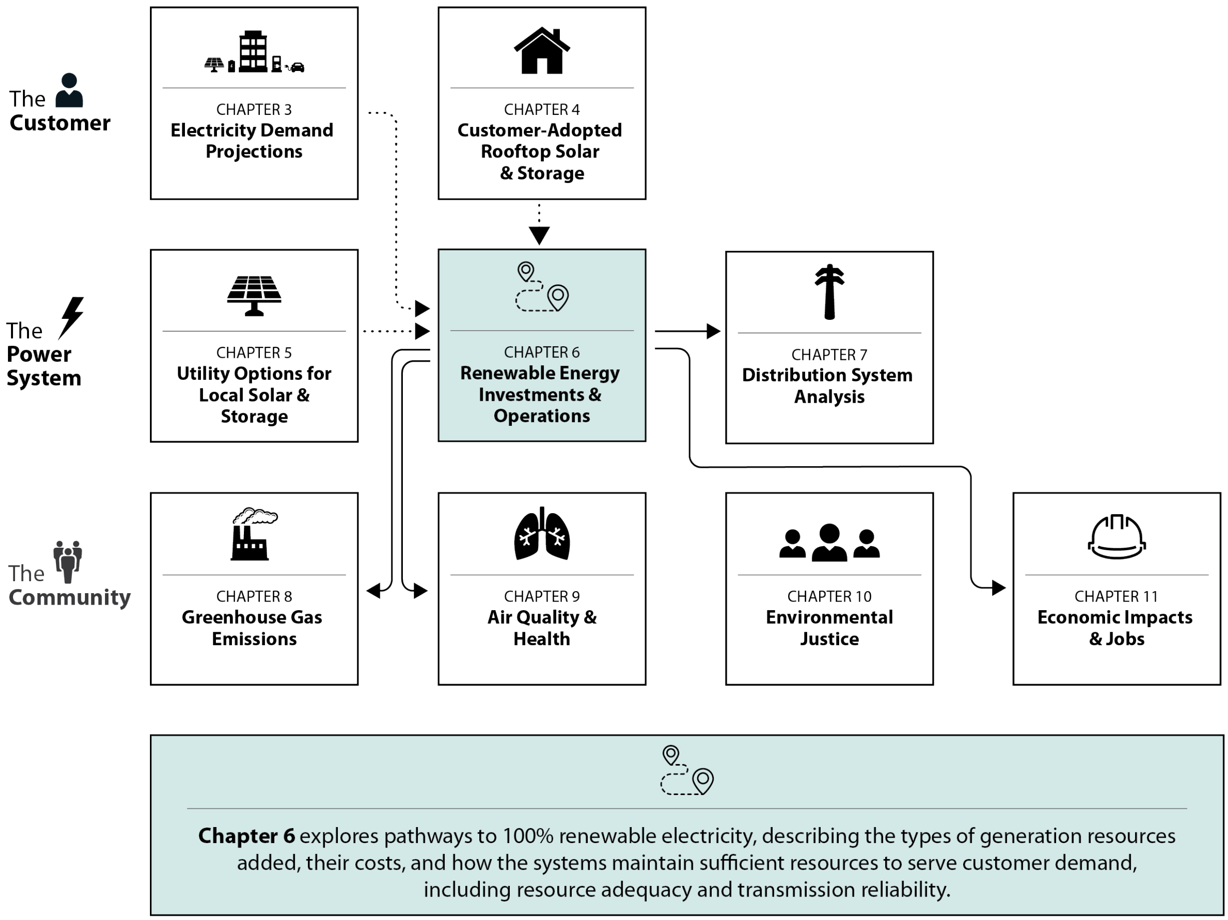

Figure 5. Overview of how this chapter, Chapter 6, relates to other components of LA100

Chapters 3, 4, and 5 provide data on electricity demand, customer-adopted solar, and potential locations for additional local solar and storage. The results from this chapter serve as inputs to the analyses of distribution grid impacts of LADWP-procured solar and storage (Chapter 7), greenhouse gas emissions in the power sector (Chapter 8), air quality emissions impacts in the power sector (Chapter 9), and expenditures to evaluate the economic and job impacts (Chapter 11).

1.2 Bulk Power Modeling Overview

The main objective of the LA100 study is to identify and evaluate pathways that achieve a 100% renewable power system for the city of Los Angeles while maintaining acceptable reliability for both the grid and end users. These pathways include major changes in the way electricity is generated, transmitted, distributed, and ultimately used by customers. As a result, the LA100 study involves applying a complex set of integrated models that capture all aspects of the power system from electricity generation to its consumption, as well as a suite of tools that enable evaluation of the economic, social, and environmental implications of the 100% renewable energy pathways.

Understanding how the bulk-scale transmission and generation system can evolve to achieve a 100% renewable electricity supply is at the heart of the LA100 study. The bulk-scale transmission and generation system (Figure 6) is responsible for generating the majority of electricity needed to meet load and for the transmission of that electricity through the high-voltage transmission network to load centers, where it is subsequently captured at receiving stations, stepped down to lower voltages, and delivered to customers through the subtransmission and distribution network. Given the crucial role of the bulk power system in meeting consumer demand, optimizing how the bulk system could evolve in response to changing load conditions and consumer behavior, growing deployments of distributed generation and storage technologies, evolving technologies, and changing mandates and policies, all while transitioning to a 100% renewable energy supply, is thus a fundamental and complex component of the LA100 study.

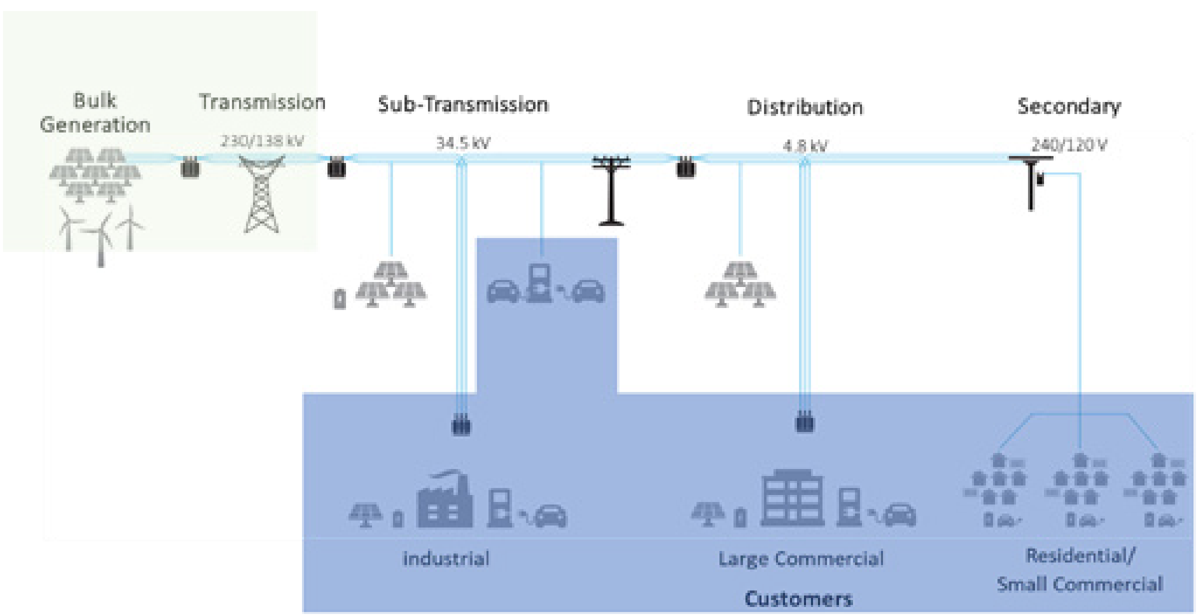

Figure 6. Diagram of the components of the LADWP power system from bulk generation to end-use consumption

The objective of the bulk-scale modeling and analysis is to identify and evaluate the costs and benefits of various pathways to achieve the 100% renewable energy target under acceptable levels of reliability and cost. Given the complexity of the power system, this cannot be achieved with a single model bulk-system model. To that end, we employ a suite of four bulk-system models that in combination identify least-cost investments pathways, simulate the operations of projected future systems in detail, and validate the future systems across a range of conditions to ensure adequacy and reliability. Figure 7 depicts these modeling steps and the text box describes how the LA100 study defines reliability.

The first step in the analysis uses a capacity expansion model (CEM) to identify the set of least-cost investments in transmission and generating assets required to achieve the 100% target. CEMs are frequently used as a component of long-term power system planning efforts, as they synthesize the many different constraints and drivers of change and investment in the power sector, including prices of technologies and fuels, policies and regulations, technology performance and constraints, fuel supply constraints, and changes in load shape and total demand, to identify investment pathways and future systems that meet the policy and/or planning criteria. However, given that these models simulate both the investment in and operation of a power system over years to decades, they necessarily use simplified representations of grid parameters, power system operations, and resource adequacy to ensure that they can be computationally solved in a reasonable amount of time. As such, they cannot be used for detailed operational analysis of future systems and do not explicitly evaluate the reliability or resource adequacy. In order to provide detailed operational simulations, validation, and assessment of reliability we employ three other modeling steps.

In the second step, a production cost model (PCM) is used to simulate the hourly chronological operation of the projected systems (under each scenario) for a full year in 5-year increments from present day to 2045. The results of these simulations allow us to evaluate whether the future projected system balances supply and demand at all times without any major challenges, and to examine how operational paradigms are changing as the system transitions to 100% renewable energy. In addition, we carry out a second set of simulations that evaluate energy balancing under conditions where various lines, transformers, and generators are out of service for extended periods of time. This set of simulations explores the robustness of the system to rare, but potentially damaging events.

PCM analysis addresses a component of reliability and resilience to certain types of system failures, but it does not explicitly evaluate the probability of dropping load under an outage event or under different weather conditions. As such the next step in the analysis uses a probabilistic resource adequacy model to evaluate whether the projected system will meet accepted reliability targets under a much wider range of possible weather conditions (including the intra-annual variability of wind and solar resources) and outages than can be considered in PCM.

Lastly, the above three modeling steps all make necessary simplifications to the representation of the complex physics of the grid. Thus, the final step in validation employs a power flow model to provide an in-depth assessment of the electrical stability of the proposed future power system under stress, both under steady state as well as following major disturbances. This step represents the physics of power generation and flow across the entire Western Interconnection at the highest level of detail.

If at any point in this modeling flow analyses reveal that the projected system is insufficient to meet load or reserve requirements, or if reliability is determined to be below an acceptable threshold, the input parameters of the CEM are adjusted, and the models re-run to produce a new solution that is then re-validated in an iterative process until a viable solution is found. The following sections review additional details on the methodology and assumptions for each of these four models.

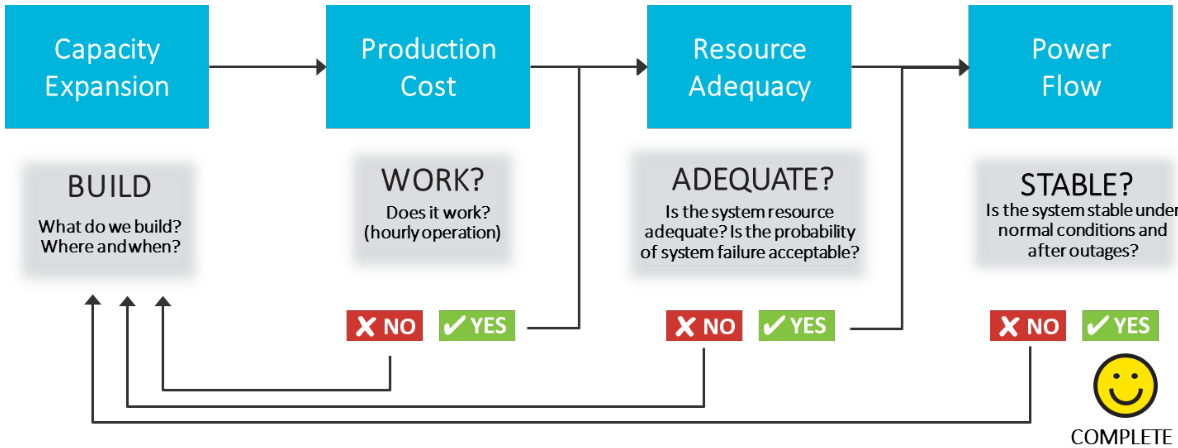

Figure 7. Bulk system modeling approach: Estimate, then refine

Text Box 1. How Does the LA100 Study Define Reliability?

Wherever possible, the LA100 study team uses terms and standards that are commonly used in the electric industry. In the United States, the main organization that defines reliability is the North American Electric Reliability Corporation (NERC). Reliability encompasses two elements—adequacy and operating reliability, which NERC defines as follows:[5]

- **Adequacy** is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.
- **Operating reliability** is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

Adequacy, or resource adequacy, represents the ability of LADWP to have enough generation—at the right locations and the right availability—to keep the lights on. This ability also requires LADWP to have sufficient transmission to deliver that power to all customers. This ability also includes ensuring that the supply is available on the hottest summer days, and even when "reasonable" outages occur. All power plants and transmission lines occasionally fail, and an adequate system has sufficient spare capacity to come online and replace capacity that fails or need to be taken out for maintenance. An important element of maintaining adequacy is estimating the availability of variable resources such as solar and wind throughout the year, and in particular during times of expected system stress. Another element is understanding the role of energy storage.

The LA100 study uses a mix of modeling tools to assess the adequacy of the system. First, a capacity expansion model is used to identify a mix of resources that should provide enough spare capacity to meet load during all hours of the year. The adequacy is then tested by simulating the resulting system on an hour-by-hour basis, ensuring that demand is always met on all points of the system, with sufficient spare capacity to withstand significant outages that can last for days.

The second component (operating reliability) essentially ensures that the lights stay on even when unexpected things happen. There is some overlap between the adequacy and operating reliability. Adequacy is intended to ensure that sufficient capacity is available when things go wrong such as an outage. Operating reliability means that the system can still operate in the seconds and minutes after the outages. The LA100 study evaluates several aspects of operating reliability. First, it checks to ensure there are adequate operating reserves, or capacity that can quickly respond to an outage within seconds or minutes. Next, it simulates actual outages of hundreds of components in the LADWP system, ensuring that the supply of energy is maintained, and equipment is not damaged by overloads.

The table below summarizes various factors related to adequacy and operational reliability. The first column presents the elements of each of the two subcategories. The second column describes how LA100 establishes the necessary conditions needed to maintain of each component. The third column describes how it is checked. Other aspects of reliability, such as system restoration, are not addressed in this study.

[5] NERC, *Definition of "Adequate Level of Reliability* (North American Electric Reliability Corporation, n.d.), https://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

	How Established	How Validated
Resource Adequacy		
Resource adequacy under normal conditions	The capacity expansion model (CEM) requires that the planning reserve margin (PRM) is met in all years over the study time horizon; the PRM is set at a level that should ensure sufficient generation capacity exists to meet target planning capacity. The CEM also considers the thermal capacity of transmission and ensures sufficient transmission capacity exists to deliver energy to all points.	A production cost model (PCM) and probabilistic resource adequacy model are used to simulate the system at high temporal resolution to ensure that the identified system (by the CEM) results in no unserved energy under normal conditions and that the probability of unserved energy during a component outage event is below a target threshold.
Resource adequacy under extreme weather	Same as above. PRM accounts for weather variability.	Same as above.
Resource adequacy under short-term outage conditions	Same as above. PRM accounts for outages.	Same as above. Comprehensive set of outages evaluated by probabilistic resource adequacy model.
Resource adequacy under extended outages	Same as above. PRM accounts for extended outages.	Use PCM to quantify and evaluate any level of unserved energy under specific extended outage scenarios.
Transmission adequacy	CEM also builds sufficient transmission to deliver energy to all points.	PCM checks basic adequacy for all hours using DC optimal power flow. Power flow modeling performs a more detailed analysis using AC optimal power flow, but only for a few moments.
Operating Reliability		
Reliability with un-forecasted wind and solar ramping or other random net load variability	The CEM enforces regulating and flexibility reserves to ensure sufficient capacity exists to meet ramping needs across various timescales.	Ensure PCM does not demonstrate unmet reserve requirements.
Post Contingency Reliability	In addition to the PRM, the CEM enforces a contingency reserves requirement—capacity available to provide energy effectively immediately should a system failure occur. Contingency reserves are required to be predominantly co-located with load (in-basin).	Enforcement of contingency reserves checked by PCM. Actual post-contingency event analysis performed by power flow modeling.

1.3 Capacity Expansion

Capacity expansion analysis is the central modeling element of the LA100 study, as it produces the generation mix and estimates the total system costs associated with each final scenario. Within the CEM step, the LA100 study identifies future generation and transmission portfolios to achieve renewable energy targets at least cost.

1.3.1 The Resource Planning Model

Modeling the expansion of the bulk power system, including utility-scale (non-customer-sited) generators and transmission, is performed with the Resource Planning Model (RPM).[6]

RPM is an NREL-developed CEM that co-optimizes generation and transmission expansion, moving forward in 5-year increments. Investment decisions for the type, amount, and location of new capacity are determined with a least-cost optimization that ensures the provision of power system resources required to meet load reliably in all hours (capacity, energy, and ancillary services), and meets all other environmental constraints, regulations, and policies.

The overall structure of RPM is depicted in Figure 8. The least-cost optimization algorithm depicted on the righthand side of the diagram minimizes overall system cost, including capital costs, fixed and variable O&M costs, and fuel costs. Hourly dispatch is modeled for 5 days that represent the low, mid, high, peak load, and low variable generation conditions seen throughout a year. Each hourly step balances generation with load, maintains the required amount of reserve capacity, and remains within operational constraints for individual generators and transmission paths.

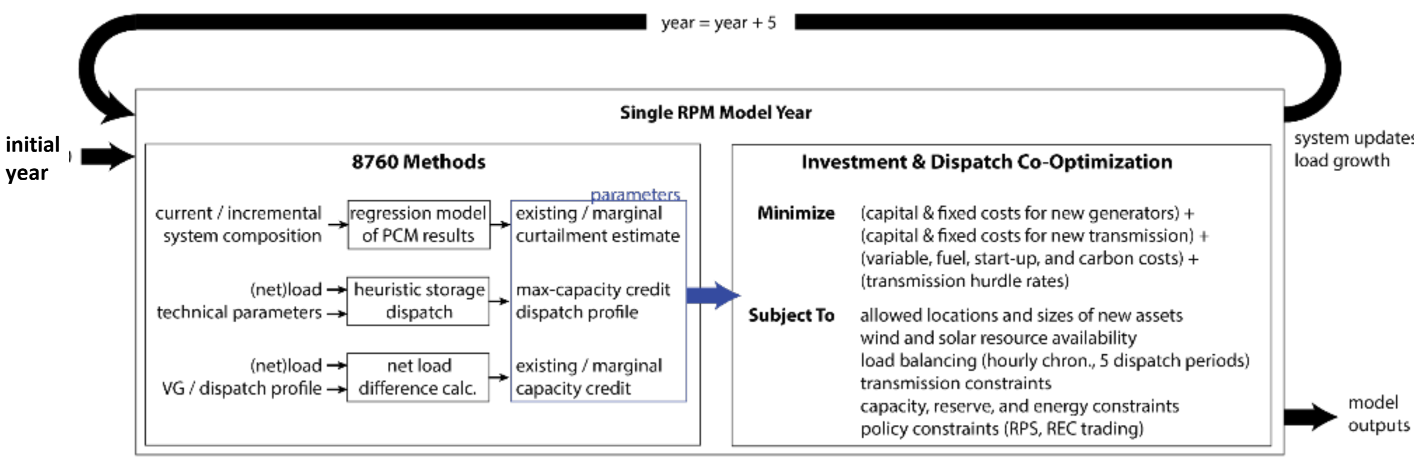

Figure 8. Relationship between RPM's investment-optimization model (right) and variable generation/flexibility-related calculations (left)

[6] "Resource Planning Model," NREL, https://www.nrel.gov/analysis/models-rpm.html

RPM supplements its reduced dispatch period structure with additional methods that capture capacity credit and curtailment estimates, which are key elements when analyzing the economic contribution of variable generation. These elements are shown on the left side of Figure 8, and these parameters are then used in the optimization problem to ensure that technologies' flexibility is appropriately valued, including multiple energy-storage technologies.

In determining least-cost optimal technology mixes, RPM is essentially identifying the best way to satisfy the suite of system requirements that ensure (to the greatest degree possible) a lowest-cost reliable power system under changing market and policy conditions. RPM includes a lengthy set of both physical and environmental/policy constraints, but the core set of constraints governing power system operation and investment, include:

- **Energy requirement:** Ensures sufficient supply of electrical energy to meet customer demand. RPM also captures the ability of certain resources to shift generation from low- to high-price times.
- **Total firm capacity requirement:** Ensures that there is sufficient capacity available to reliably serve load during times of system stress, often peak-load or peak-net-load conditions, of which the magnitude and timing is uncertain. The total firm capacity requirement is typically defined as peak load plus a predetermined margin (the planning reserve margin) for reliability. Firm capacity differs from total nominal capacity—it is the portion of nominal capacity that is reliably available during these times of system stress. Technologies that are often referred to as "firm capacity resources" or "dispatchable resources," such as geothermal energy or combustion turbines, have high net dependable capacity (or "capacity credit") ratings, typically 90%–95%[7] of their nominal capacity ratings, and are therefore frequently relied on to provide firm capacity services. Wind and solar resources also provide firm capacity, but their capacity credit is dynamic with system composition and load and is typically lower than those of firm capacity assets. Finally, energy shifting resources including storage and demand response can also provide firm capacity, but similar to wind and solar assets, their capacity credit is dependent on the system composition and load, as well as other key characteristics of the specific resources (such as duration of storage, in the case of batteries).
- **Operating reserves (contingency, regulation, and flexibility) requirement:** Ensures that there is sufficient capacity that can quickly vary output to 1) address unexpected generator or transmission line outages, 2) respond to short-term variation and forecast errors (in expected load, wind, and solar output), and 3) balance out longer-term (1- to 4-hour) uncertainty in net-load, including ramping.[8]

RPM models the entire Western Interconnection, which includes all or parts of 13 states in the western United States. Figure 9 and Figure 10 show the wind and solar resource throughout the footprint. This comprises 36 modeled balancing areas (BAs) also called zones, which are the primary regional units in RPM (not shown). Embedded within this zonal structure, the model has a "focus region" within which generation units, transmission lines, and loads are represented with a high level of detail. In the focus region (here, including the transmission paths shown in

[7] Firm capacity resources are assigned capacity credits less than 100% to account for potential unexpected outages of the assets during the times of system stress.
[8] See Table 31 for further discussion of treatment of operating reserves.

Figure 9 and Figure 10 along with the lines nearby LADWP's service territory, represented by a star), the optimization is carried out on a nodal level. The remaining BAs are treated as singular zones and transmission interfaces to capture power transfers into and out of the focus region and between connected BAs. Figure 9 and Figure 10 also indicate assets LADWP wholly or partly owns or has rights to that exist outside the physical Los Angeles Basin. This includes transmission lines (such as the Pacific DC Intertie which extends to Celilo station near the Washington and Oregon border) and generators (such as the Intermountain Generating Station in Utah and Palo Verde Nuclear Generator in Arizona). See Figure 13 for a detailed illustration of the network topology as modeled in RPM and PLEXOS.

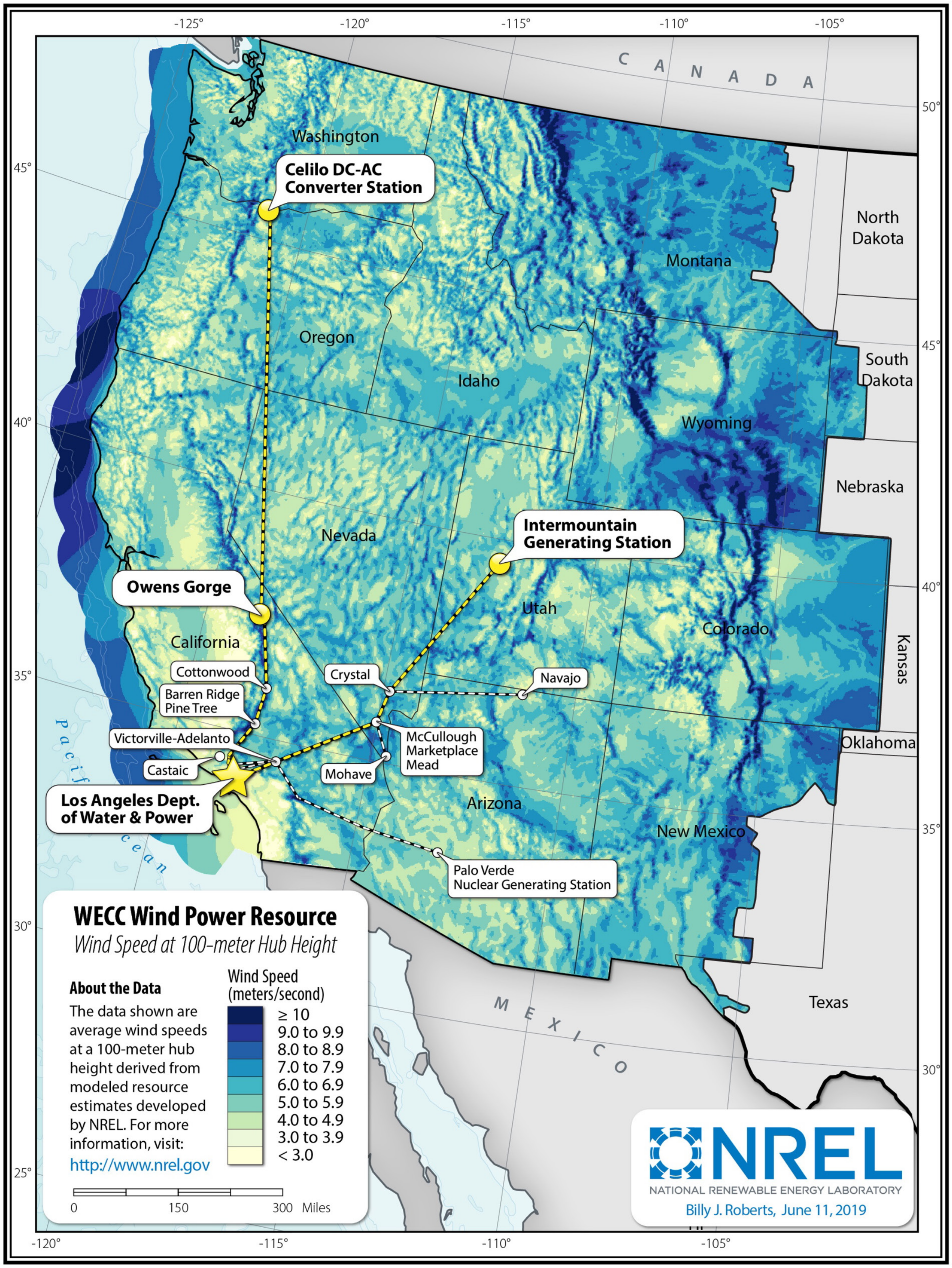

Figure 9. Map showing wind resource throughout the Western Interconnection and out-of-basin transmission in the Resource Planning Model, highlighting LADWP (starred) and other assets that LADWP is fully or partially entitled to use

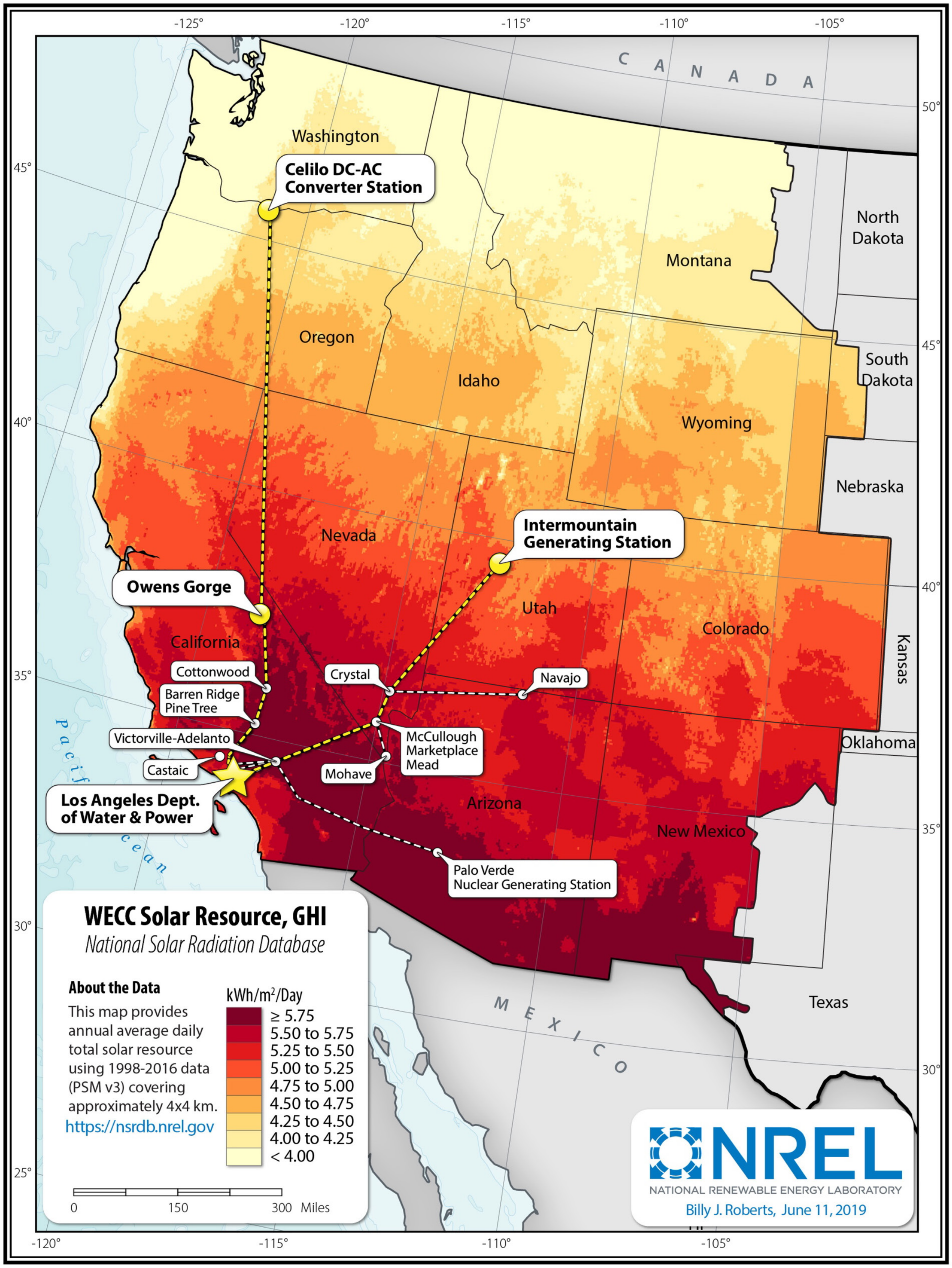

Figure 10. Map showing solar resource throughout the Western Interconnection and out-of-basin transmission in the Resource Planning Model, highlighting LADWP (starred) and other assets that LADWP is fully or partially entitled to use

Appendix A provides additional details on the RPM model.

1.3.2 Data Inputs

For the LA100 study, the focus region (with unit level representation of generating and storage resources and nodal representation of >69kV transmission) is comprised of the LADWP system. For modeling purposes, the service territories of other load-serving entities within the LADWP balancing area[9] are included as part the Southern California Edison zone of CAISO. To characterize renewable resources across the Western Interconnection, the model includes 56 PV, 45 concentrating solar power (CSP), 71 wind, and 34 geothermal resource areas that specify the location-specific resource potential (developable area after accounting for various land use exclusions), performance (annual and hourly capacity factors), and grid interconnection distances of all resources within each region. Boundaries of the resource regions are generally defined to provide greater resolution in areas expected to see substantial resource development. For example, in the case of the LA100 study, because there is a large amount of solar PV resource relatively close to the LA Basin, we define smaller (and more highly resolved) solar resources in this area compared to the rest of the interconnection.

Within the simulations of the LA100 scenarios, we represent hydrogen combustion turbines (H_2-CTs) and hydrogen fuel cells as explicit technologies, and we also capture the electricity requirements (load) to produce and store hydrogen fuel (as liquid ammonia). These technologies therefore represent two forms of long-duration storage. Both technologies use zero- or low-variable cost generation to create hydrogen, which is subsequently converted to and stored as ammonia. The ammonia could then be either 1) used directly in combustion or, as our analysis assumes, 2) fractured to create hydrogen, which is subsequently used in a CT or fuel cell. With exception of the planned phase-in of hydrogen fuel at Intermountain Power Plant (IPP), new H_2-CTs and fuel cells are not allowed prior to the 2030 solve year.

Renewable CT technologies, on the other hand, are assumed to use a market-purchased fuel (as opposed to self-produced fuel), and regardless of the type of renewable fuel used (hydrogen, biofuel, biogas, synthetic natural gas, are characterized more generally as a renewable CT (RE-CT). However, given that robust markets (and supply infrastructure) for hydrogen and synthetic methane do not currently exist, we assume that prior to 2045, RE-CTs are fueled with a liquid biofuel or biogas. By 2045, we assume that development of robust markets for hydrogen or synthetic methane develop, and therefore that these CTs are converted to hydrogen fuels. Given that the Early & No Biofuels scenario does not allow the use of biofuels or biogas, RE-CTs are not allowed to be built until 2045 in that scenario, at which point they are assumed to be fueled by hydrogen. Renewable CT technologies are assumed to have synchronous condenser capabilities to provide grid support services while not operating.[10] Table 2, Table 3, and Table 4 Table 4 summarize assumptions for renewable energy technologies, renewable CT and fuel options, and storage technologies, respectively.

[9] Burbank W&P and Glendale W&P

[10] The availability of inverter-based resources to provide grid support services may negate the need for some of the in-basin synchronous condensers, particularly considering the relative losses associated with operating synchronous condensers. A comparison of approaches and cost-effectiveness of different resources for voltage and frequency support will be required as the technologies evolve in the coming years and decades.

Table 2. Modeling Assumptions for Renewable Energy Technologies

	Capital Cost in 2030 (2019 $/kW)	Capital Cost in 2045 (2019 $/kW)	Technology Subcategory
CSP (no thermal storage)	3,628	3,118	No thermal storage
Geothermal	4,208	3,904	Hydrothermal; flash cycle
	5,429	5,036	Hydrothermal; binary cycle
	14,442	13,396	Near-hydrothermal; flash cycle
	32,112	29,786	Near-hydrothermal; binary cycle
	14,442	13,396	Deep enhanced system; flash cycle
	32,112	29,786	Deep enhanced system; binary cycle
Utility PV	1,266	1,065	Out-of-basin single-axis tracking
	1,862	1,588	In-basin fixed-tilt
Wind	1,417	Resource-specific: 1,185–1,251	Onshore
	Resource-specific: 2,017–3,126	Resource-specific: 1,237–1,645	Offshore

Costs are taken from the 2019 Annual Technology Baseline, adjusted for inflation from 2017 to 2019 dollars, and scaled using regional multipliers from the U.S. Energy Information Administration's Capacity Cost Estimates for Utility Scale Electricity Generating Plants (see Table 4). Utility PV costs are reported in $/kW_{AC}$.

Table 3. Modeling Assumptions for Storable Renewable Fuels

	Capital Cost in 2030 (2019 $/kW)	**Capital Cost in 2045 (2019 %/kW)**	**Fuel Types**	**Fuel Procurement**	**Generation Costs**	**Eligibility Restrictions**
Hydrogen-CT	4,542	3,226	Hydrogen stored as ammonia; combusted as hydrogen	On-site production and storage. Round-trip efficiency: 25%	Reflected in cost of increased generation and conversion losses. Effective fuel cost is the variable cost of electricity *1.5	Starting 2030
Hydrogen Fuel Cell	5,313	3,774	Hydrogen stored as ammonia; used as hydrogen	On-site production and storage. Round-trip efficiency: 45%	Reflected in cost of increased generation and conversion losses; no direct cost	Starting 2030
RE-CT	1,055	1,000	Biofuel through 2040, then any renewable fuel in 2045 (model assumes hydrogen)	Market-procured	Fuel cost is $20/MMBTU. Variable generation cost is $184/MWh until 2040 $167/MWh in 2045	Starting 2030 for all but Early & No Biofuels; Starting 2045 for Early & No Biofuels

Table 4. Modeling Assumptions for Storable Technologies

	Capital Cost in 2030 (2019 $/kW)	Capital Cost in 2045 (2019 $/kW)	Storage Duration (hours)	Battery Capacity Ratio
CSP with Thermal Energy Storage	3,412	2,760	6	NA (ratio of solar field to power block is 0.8)
	7,114	5,877	14	NA (ratio of solar field to power block is 3.3)
In-Basin Utility PV Battery	2,743	2,347	4	1 MW PV : 0.71 MW Battery
	4,016	3,445	8	1 MW PV : 1 MW Battery
Out-of-Basin Utility PV Battery	2,206	1,876	4	1 MW PV : 0.71 MW Battery
	1,887	1,602	4	1 MW PV : 0.5 MW Battery
	3,480	2,974	8	1 MW PV : 1 MW Battery
Utility Battery Storage	837	680	4	N/A
	1,297	1,054	8	N/A
Pumped Hydro Storage	Project-specific: 1,500–2,784	Project-specific: 1,500–2,784	6–12	N/A

Appendix B provides additional details on data inputs for RPM.

1.3.3 Translating the Scenarios into Models

To understand the tradeoffs of alternative pathways to achieve a 100% renewable power system, the LA100 study evaluates four descriptive scenarios of future change that differ in terms of assumptions regarding:

- Technologies that qualify as “renewable” or clean and can thus to contribute to a 100% system
- Assumed costs and feasibility of developing new or upgrading existing transmission
- Assumed adoption of residential and commercial PV systems
- Key policy design criteria, including year of compliance (2035, 2045), the eligibility of renewable electricity credits (RECs) for a portion of compliance, and whether the 100% target has a basis in sales or generation.

We evaluate each of these scenarios using alternative projections of the evolution of load and associated assumption about energy efficiency and load flexibility (demand response) to understand how the evolution of load may impact the quantity, type, location, and cost of alternative generation, storage, and transmission resources. Figure 11 summarizes the scenarios, which are described in more detail below.

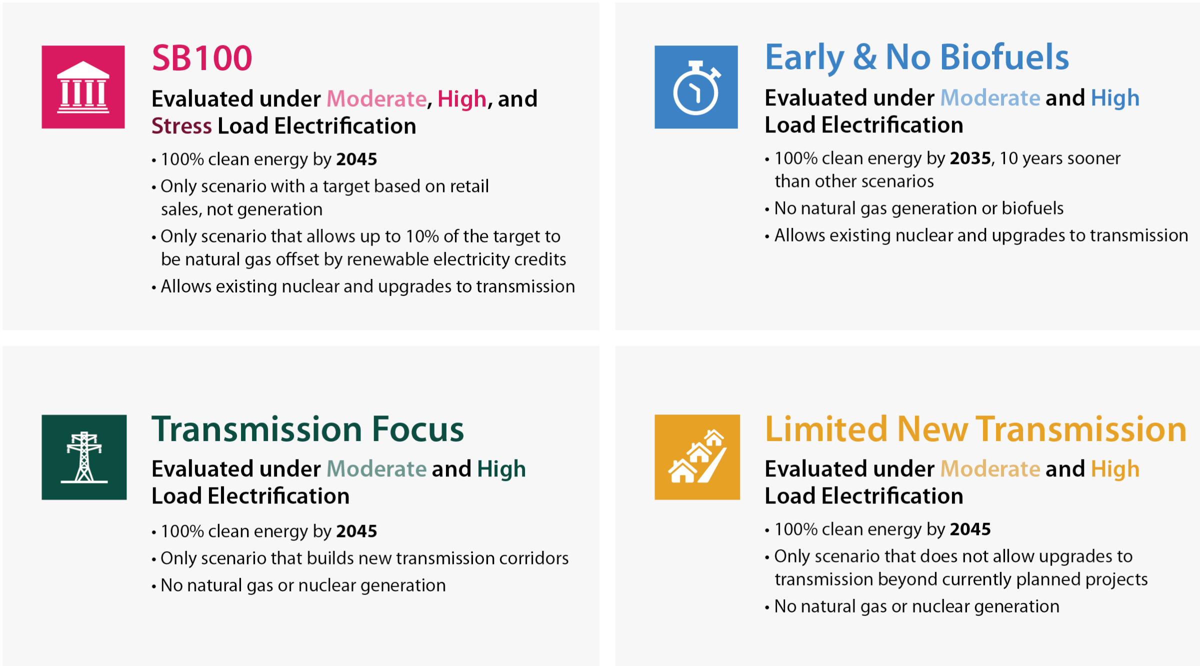

Figure 11. Overview of the LA100 scenarios

The four LA100 scenarios evaluated are the following:

- **Senate Bill 100 (SB100)**: This scenario represents a pathway toward compliance with the California statewide policy, Senate Bill 100, which requires 60% of total sales to be renewable energy by 2030, and 100% of total sales to be zero-emitting generation by 2045. We assume that unbundled RECs are permitted to be used for a portion (10%) of compliance for both the 2030 and 2045 targets. This is the only scenario with the renewable energy target based on sales rather than generation (which means that a percentage of total generation equal to transmission and distribution losses can be supplied by non-renewable sources), and the only scenario that allows existing natural gas plants (other than the planned OTC retirements) to remain online through 2045 if their usage is offset with RECs.
- **Early & No Biofuels (Early/NoBio)**: This scenario diverges from SB100 in three key ways. First, the targets are based on a fraction of total generation (not sales or load) and as a result are somewhat more stringent, as losses need to be covered with renewable generation as well. Second, this scenario requires achievement of the 100% target 10 years earlier—by 2035. Third, this scenario does not allow the use of generating sources that rely on combustion of biofuels. This scenario achieves 100% renewable or nuclear (as a fraction of total generation) by 2035.
- **Transmission Focus (Trans. Focus)**: This scenario describes a future in which transmission upgrades or new builds are more easily executed (due to streamlined permitting, increased social acceptance). In addition, under this scenario it is assumed (exogenously) that an existing out-to-in basin transmission pathway (the Victorville–Century path) is converted to DC and substantially upgraded in capacity to create a transmission backbone into the basin (Figure 12). In addition, it is assumed that new DC connections are built between Century and Harbor (along the LA River) and between Harbor and Haynes and Harbor and

Scattergood via submarine transmission cables (see Figure 12). Like the Early & No Biofuels scenario, the target is based on a fraction of generation (not load), but the 100% target date is 2045. This scenario does not allow fossil or nuclear fuels in 2045.

- **Limited New Transmission (Ltd. Trans.)**: This scenario describes a future in which distributed resources are more heavily relied upon to meet the 100% target. High levels of distributed PV adoption are achieved through continued policy support or other means and due to cost declines. In addition, the scenario prohibits new or upgraded transmission (with the exception of new spur lines outside the LA Basin that are necessary to connect existing transmission to remote renewable resources) further driving the value of in-basin resources. The assumed target for 100% compliance (as a fraction of generation) is 2045. This scenario does not allow fossil or nuclear fuels in the 2045 compliance period.

Each of the LA100 scenarios is simulated using two different projections of the future evolution of demand, energy efficiency, and demand response: Moderate and High load electrification. These load projections vary in terms of the level of electrification of end-use services, the improvements in energy efficiency, and the availability of flexible load or demand response. The SB100 scenario also includes a Stress load scenario, which assumes a future of high electrification combined with low energy-efficiency improvements and demand response—circumstances that lead to more challenging load conditions.

In addition to the four LA100 scenarios, as a point of comparison we also simulate the LADWP 2017 Integrated Resource Plan (2017 IRP). This scenario explicitly captures, as best as possible, the LADWP 2017 Strategic Long-Term Resource Plan (SLTRP) *Recommended* Case. The 2017 SLTRP provides projections through 2037, and as such, this scenario is simulated only through 2035 because the CEM operates in 5-year increments. The scenario achieves 65% renewable energy (as a fraction of load) by 2035.

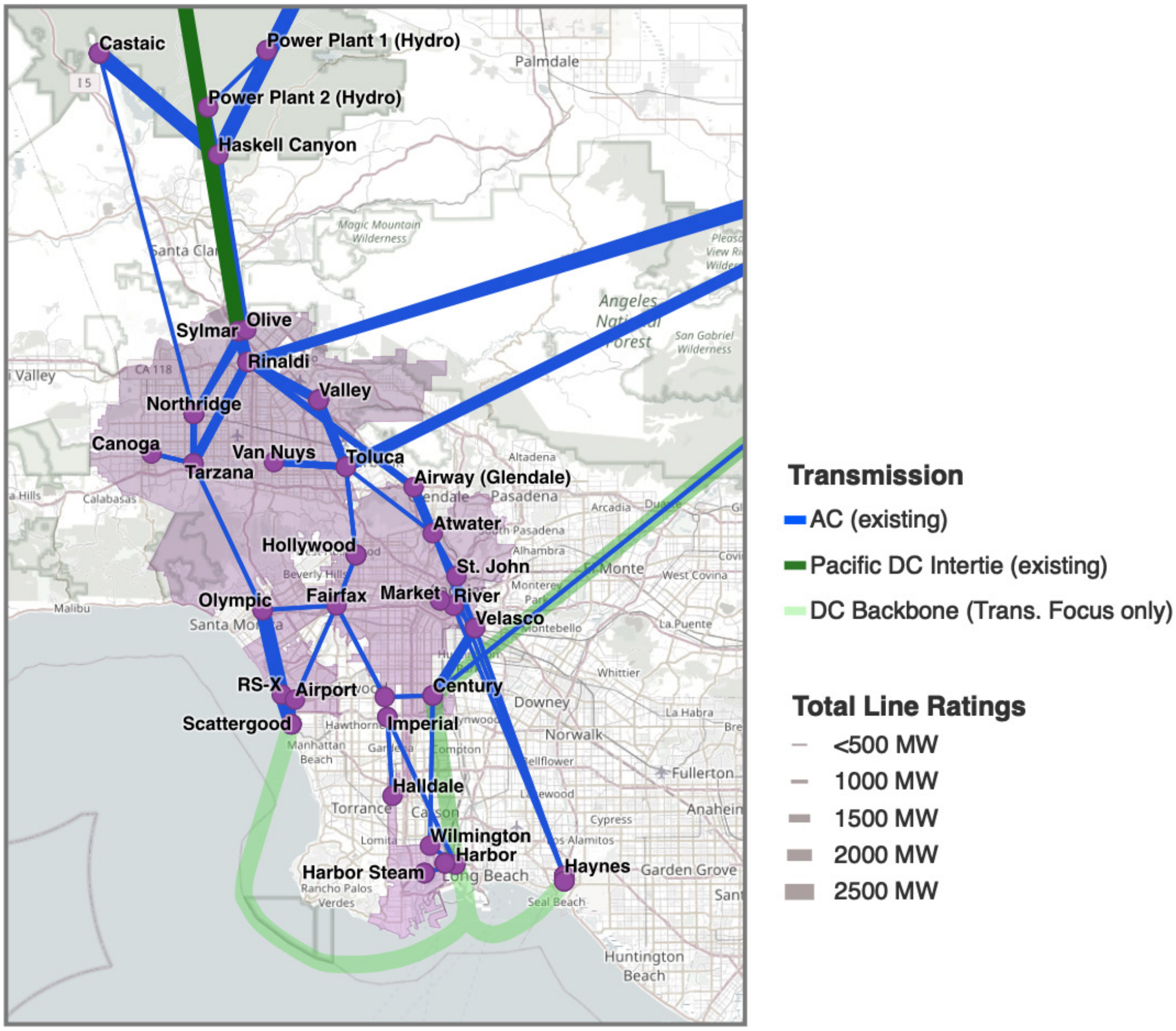

Figure 12. Depiction of the DC transmission backbone that is assumed to be constructed under the Transmission Focus scenario

Summary of Assumptions—Bulk System Expansion

- The study uses NREL's capacity expansion model, RPM, to identify the least-cost mix of resources needed to reliably meet electricity demand under various constraints specific to each scenario (e.g., eligible technology).
- The model is run in 5-year time steps, beginning 2020 through 2045. New generation builds are allowed starting 2025; new transmission starting 2030.
- Once-through cooling (OTC) units are retired before 2030 in all scenarios, except a reference case that extends only until 2036 (and is not included in the LA100 scenario results). Other (non-OTC) investments identified in the 2017 IRP Recommended Case are included for consideration in all scenarios.
- Unbundled renewable energy certificates (RECs) are allowed to contribute toward compliance in the final year of only the SB100 scenario. Exported clean energy does not count toward compliance and natural gas generation cannot be offset by surplus renewable energy unless RECs are allowed. Existing restrictions on REC eligibility and trading under the current CA RPS are assumed to continue into the future.
- For planning (investment) decision-making, RPM assumes that all energy, capacity, and operating reserve requirements must be met with LADWP-owned or -contracted assets or customer-sited distributed PV.
- Generation and storage technology cost and performance assumptions are from NREL's 2019 Annual Technology Baseline.
- Fuel price assumptions are based on a compilation of both AEO 2019 and LADWP projections.
- The model exogenously incorporates estimates of adoption of customer-sited distributed energy resources from the dGen model. However, the model makes endogenous decisions on the investment and siting of distribution connected utility-owned PV, and it incorporates cost information associated with distribution system upgrades required to integrate this capacity.
- RPM does not explicitly model the cap-and-trade nature of Assembly Bill 32, but instead represents the costs of compliance by requiring CO_2 emitting generators to purchase and retire carbon allowances for each ton of CO_2 emitted. CO_2 allowance price projections are from the California Air Resources Board Preliminary GHG Price Projections.

1.4 Production Cost Modeling

The next phase in the bulk modeling analysis, as illustrated in Figure 7, uses PLEXOS,[11] a commercially available PCM (sometimes referred to as a unit commitment and dispatch model), to simulate the hourly operations of the future systems identified by the CEM and to validate the ability of those systems to balance generation and load at all times. The objective of a production cost model is to optimize the scheduling and dispatch of generation resources to meet load in the most cost-effective manner within the context of constraints (e.g., renewable resource and transmission availability, operational practices).

The production cost modeling begins with the system generated by the CEM, including the types, capacities, and locations of transmission, renewable generation, and conventional generation, along with hourly load and variable generation data. These data are passed to the

[11] "PLEXOS Market Simulation Software," Energy Exemplar, https://energyexemplar.com/products/plexos-simulation-software/.

PCM, along with hourly operating reserve requirements.[12] The CEM employed for LA100 (RPM) uses a simplified dispatch for each year to inform investment decision making decades into the future. Specifically, it simulates chronological hourly dispatch for a set of 5 representative days sampled throughout the year and then scales those results to understand annual generation behavior. This allows the model to consider key operational constraints and challenges but remain simple enough to maintain computational tractability. However, because the CEM does not explicitly simulate all 8,760 hours of dispatch for each year within the time horizon, nor does it account for unit commitment, it is unable to resolve many operational constraints key to ensuring energy balance. So, the PCM simulates hourly operation of the grid to measure operational costs and validate the balance of supply and demand, check for reserve violations, and measure basic transmission adequacy using a linearized DC approximation of the transmission network. The PCM (PLEXOS) provides necessary feedback to the CEM to determine more definitively if the built system can operate feasibly. If PLEXOS identifies unserved energy (i.e., load that the system is unable to serve) or other constraint violations (e.g., reserves shortages or hydro violations), then the CEM can be refined to incorporate additional constraints or requirements, which directly impacts the resulting build decisions (see Figure 7).

Simulations are carried out under normal operations as well as with assumed long-term outages of key assets, such as what might occur when transmission is taken offline due to fire hazards. The objective is to determine whether load can be met despite access being cut off to some resources or increased strain and congestion on the transmission system due to the outage of important transmission lines or transformers. This type of analysis can be consequential for power systems that rely more heavily on remote resources (e.g., out-of-basin solar and wind that is separated from load centers in LA by transmission that is susceptible to failure) to charge energy storage that is located near load centers (e.g., in-basin batteries and pumped-hydro energy storage [PHES]). Under the long-duration outage simulations, key generation and transmission assets are assumed to be unavailable for a full year of operation.[13] These simulations identify whether the energy balance of the system (subject to constraints on thermal ratings and voltage phasor angles of transmission lines) is robust to a diverse set of long-duration outages scenarios that range from more minor single line failures to extreme multi-line or generator failures.

The LADWP power system is interconnected to the rest of the Western Interconnection, and as such LADWP can exchange electricity resources—energy, capacity, and operating resources—with other utilities or balancing areas to help balance their system and ensure reliability at least costs. However, the LADWP planning process requires that sufficient resources are either owned or explicitly contracted for to ensure that LADWP can meet load at all times without any reliance on short-term purchases of energy, capacity, or reserves. Therefore, for the LA100 study the

[12] Operating reserves represent generator capacity available to address variability and uncertainty in generation supply and demand, and include contingency, flexibility, and regulating reserves. Reserves can be held by partially loaded generators (or offline generators, depending on the type of reserve) with sufficient ramp to respond in a given timeframe.

[13] The set of generation and transmission outages are derived from LADWP's P1-P7 and extreme contingencies that are typically analyzed using AC power flow modeling in transmission planning studies. NREL has added its own additional outage cases throughout the course of the study to rigorously test the system under high penetrations of out-of-basin renewable energy. The largest case overall is a P7 affecting Eldorado-Lugo-Lugo-Mohave, which removes 5,716 MW of thermal rated capacity. The largest into-basin outage is the case we created to represent the Saddleridge Fire, which eliminates 5,637 MW of transfer capacity. In-basin critical N-1-1s remove as much as 1,632 MW of capacity.

PCM modeling and analysis requires that the LADWP system is balanced without reliance on imported services of any kind—in short, the LADWP power system is islanded and operated in isolation. To create an "islanded" LADWP scenario, we removed all Western Interconnection generators, nodes, and lines that were not within the LADWP territory from the underlying representation of the full Western Interconnection within the PLEXOS network topology/database.[14] This ensures that all LADWP demand must be served only by LADWP generation in every hour and is the "base case" configuration for all runs. However, in addition to the islanded simulations, we also simulated a set of "integrated" scenarios that include the generation fleet and transmission network topology of the entire Western Interconnection (i.e., inclusive of future transmission upgrades) and allow perfectly coordinated exchange of electricity services between LADWP and all other BAs within the Western Interconnection.

The goal of the PCM step is to test the operational impacts of capacity expansion scenarios, provide feedback to help fine-tune capacity expansion analyses, and offer a detailed picture of hourly dispatch across scenarios as a final study result.

Some key outputs of PCMs include:

- Resource adequacy information such as identification of any unserved load or unserved reserves
- Generation mix at different timescales, from hourly to annual aggregation
- Total variable operating cost of generating electricity (including fuel costs, startup and shutdown costs, and variable O&M costs)
- Dispatch and utilization of energy-constrained resources such as hydro, pumped storage, batteries, and demand response
- Actual compliance with emissions and renewable energy targets, considering curtailment (available renewable energy that is unable to be used to serve load)
- Resource mix providing reserves on an annual basis and at any given time
- Usage and congestion of transmission system (i.e., imports and exports, flows along important paths, phase-shifting transformer tap operation, scheduling of flows on DC interties)
- Periods of interest (e.g., high renewables/low load periods, low renewables/high load periods) that may require further stability testing via a power flow study.

[14] One complicating factor is that LADWP owns or is entitled to portions of transmission corridors and partial output from generators throughout the western United States. To account for this, we simply de-rate these plants and lines to match the capacity entitled to LADWP. This simplification has drawbacks for both types of assets: by representing only a portion of generating capacity, unit commitment may differ from what it would be when considering demand by other entities for generation from the plant as a whole; and since power flows across the transmission network are governed by physical laws and are determined by all generation and load across the Western Interconnection and the physical structure of the network, power flows in the physically islanded representation of the LADWP system differ somewhat from what LA's share of flows would be when modeling the whole interconnection. The generators LADWP has partial ownership of include Palo Verde nuclear plant, Intermountain Power Plant (IPP), and Hoover hydropower plant. LADWP shares transmission rights on a host of lines and transformers, including the Pacific DC Intertie, the Southern Transmission System (STS, a DC intertie connecting IPP in Utah with the Adelanto Switching Station in California), and several other routes northeast of LA.

Summary of Key Assumptions—Production Cost Modeling

- The study uses the production cost model PLEXOS to evaluate the operational feasibility of the capacity expansion projections (e.g., supply and demand balancing under normal and contingency conditions; availability of sufficient operating reserves).
- We simulate the operation of the system at hourly timescales for a full year at each of the 5-year timesteps modeled in RPM (2020–2045).
- For each scenario, we simulate the system assuming LADWP must meet energy and operating reserves solely with LADWP-owned or -contracted assets. For selected scenarios, in order to evaluate the potential benefits of broader coordination of both energy and operating reserve procurement, we also simulate a case where LADWP can exchange resources (subject to physical constraints on the system) with other BAs across the Western Electricity Coordinating Council (WECC) if such imports or exports lower overall costs (by accessing lower cost energy or reserves or creating revenue through sales).
- In addition to simulations under normal operating conditions, we also simulate a large suite of long-duration-outage scenarios to ensure that energy balance is robust not solely under normal conditions, but also under situations where key assets (either generation or transmission) may be unavailable, due to unexpected outages, for extended periods of time.
- We do not simulate forecast error for renewables or load; however, we require multiple operating reserve products that are established at sufficient levels to be able to accommodate any energy needs associated with error in load or renewable resource forecasts (see below).
- The model uses a simplified linearized DC-power-flow representation of the transmission system.
- The model holds sufficient capacity for four types of operating reserves: non-spinning contingency reserves, spinning contingency reserves, flexibility reserves, and regulation reserves. Contingency reserve requirements are the largest of 1) 738 MW, which is LADWP's entitlement to the maximum flow on one pole (i.e., one of two circuits, half the total capacity) of the Intermountain Power Project DC tie to Adelanto (also called the Southern Transmission System [STS]), or 2) LADWP's portion of the actual flow on the tie, which can reach 1,428 MW. Half of the contingency requirement must be provided by fast response resources.[15] Regulation and flexibility reserve vary as a function of renewable resource supply.
- All PV + battery generators represent loosely DC-coupled devices (i.e., the battery can charge from either the grid or the PV, but the combined output of both the battery and PV must not exceed the inverter rating).
- Distributed PV generation is assumed to be visible to LADWP for system scheduling. Behind-the meter-and other small to medium (<1 MW) distributed PV generation (those identified by the dGen model as described in Chapter 4) cannot be curtailed, but utility-owned PV generation (including larger facilities connected to distribution/subtransmission but identified by RPM) can be curtailed if economic.

[15] This heuristic requirement represents LADWP's current practices, which were adopted for the LA100 study since flows on the transmission paths noted are expected to remain among the largest single contingencies on the LADWP system. With the exception of PV + battery generators (which are typically located close to the basin across diverse locations) out-of-basin resources are not allowed to providing spinning contingency reserves. The Castaic pumped-hydro energy storage plant is allowed to provision spinning reserve even when none of its units are not generating, as its units are able to start quickly and are often already spinning at synchronous speed to provide power quality services (i.e., condensing). This ability may require additional upgrades.

- Behind-the-meter, customer-sited *storage* will be dispatched according to highest value to grid operations, on the presumption that LADWP would create a tariff to incentivize this.
- Generation of electricity to produce hydrogen or ammonia by electrolysis for use in H_2-CTs and fuel cells is accounted for in a heuristic re-dispatch that is applied to the PLEXOS results, accounting for curtailed energy or available capacity from dispatchable renewable resources such as geothermal.[16]

Appendix C provides additional detail on data sources for production cost modeling.

1.5 Resource Adequacy

RPM, the capacity expansion model being used for LA100, identifies a least-cost investment portfolio given a suite of inputs and assumptions, including load, distributed generation, technology costs, fuel costs, renewable resource availability, and location, subject to all physical, environmental, and policy constraints. To ensure that the identified systems achieve resource adequacy, RPM employs a planning reserve margin constraint including the 15% NERC recommendation and adds an additional 8% to account for the impacts of inter-annual weather variability under high-penetration renewable energy systems (for a total of about 23%). Despite this, planning reserve-margin-based resource adequacy assessments become increasingly challenging when considering systems not strictly limited to dispatchable, capacity-based resources, such as those incorporating variable renewable and storage resources. This is driven by the fact that the "firm" capacity (or capacity credit) of such resources is often less than their nameplate capacity, and dynamic with the system composition and load shape. Determining the amount of capacity credit that a variable generation or storage resource provides requires more sophisticated approaches, such as the Incremental Net-Load Duration Curve method that RPM employs. This approach assigns capacity credit to new variable resources based on the estimated reduction in the system's peak net-load resulting from the addition the new resource.[17]

In addition to the methods used in RPM to ensure resource adequacy, the PCM analysis provides further evaluation of the robustness of the identified system. Using PLEXOS, the PCM, we simulate the operation of the future systems in every hour of each (modeled) year and identify operational challenges or instances of unserved energy or unserved reserves under the given set of weather and load conditions. If any unserved energy or reserves is identified, this is an indication that the system identified with RPM is not robust and should be revised.

While RPM and PLEXOS capture important aspects of resource adequacy, neither explicitly represent all conditions—different weather conditions, different load conditions, or many other potential (although low probability) generator or transmission outages. We thus employ a probabilistic resource adequacy model (specifically, the Probabilistic Resource Adequacy Suite, or PRAS) to evaluate and ensure that the future projected systems meet acceptable reliability levels. PRAS repeatedly simulates simplified system operations under randomly drawn generator outages, calculating probabilistic metrics to quantify the risk of failing to serve demand due to insufficient resource availability. These metrics include loss of load expectation (LOLE, the probabilistic expectation of the number of time periods that could face a supply shortfall) and

[16] This is done to address the limited ability of models to optimize storage over extremely long periods.
[17] For further information, see Elaine Hale, Brady Stoll, and Trieu Mai, *Capturing the Impact of Storage and Other Flexible Technologies on Electric System Planning* (NREL, 2016), NREL/TP-6A20-65726, https://www.nrel.gov/docs/fy16osti/65726.pdf.

normalized expected unserved energy (NEUE, the probabilistic expectation of the quantity of energy that could go underserved over the time horizon studied, as a fraction of total energy demand). Synchronous wind, solar, and load time series are used to capture correlations in the availability of supply and demand. The LA100 study targets a baseline resource adequacy level of 2.4 hours/year LOLE and an EUE of 0.001% (10 ppm) of energy demand.

The LADWP system modeled in PRAS assumes no exchange of resources with the rest of the Western Interconnection, except for imports from LADWP's share of out-of-footprint resources such as Palo Verde and Hoover generating stations. Internally, the LADWP network is simplified to six transmission regions (four in-basin and two out-of-basin, shown as N, S, E, W, and Northern Path and Vic–LA in Figure 13, respectively), with power exchanges between the regions limited to the sum of the interregional line flow limits used in PLEXOS production cost modeling.

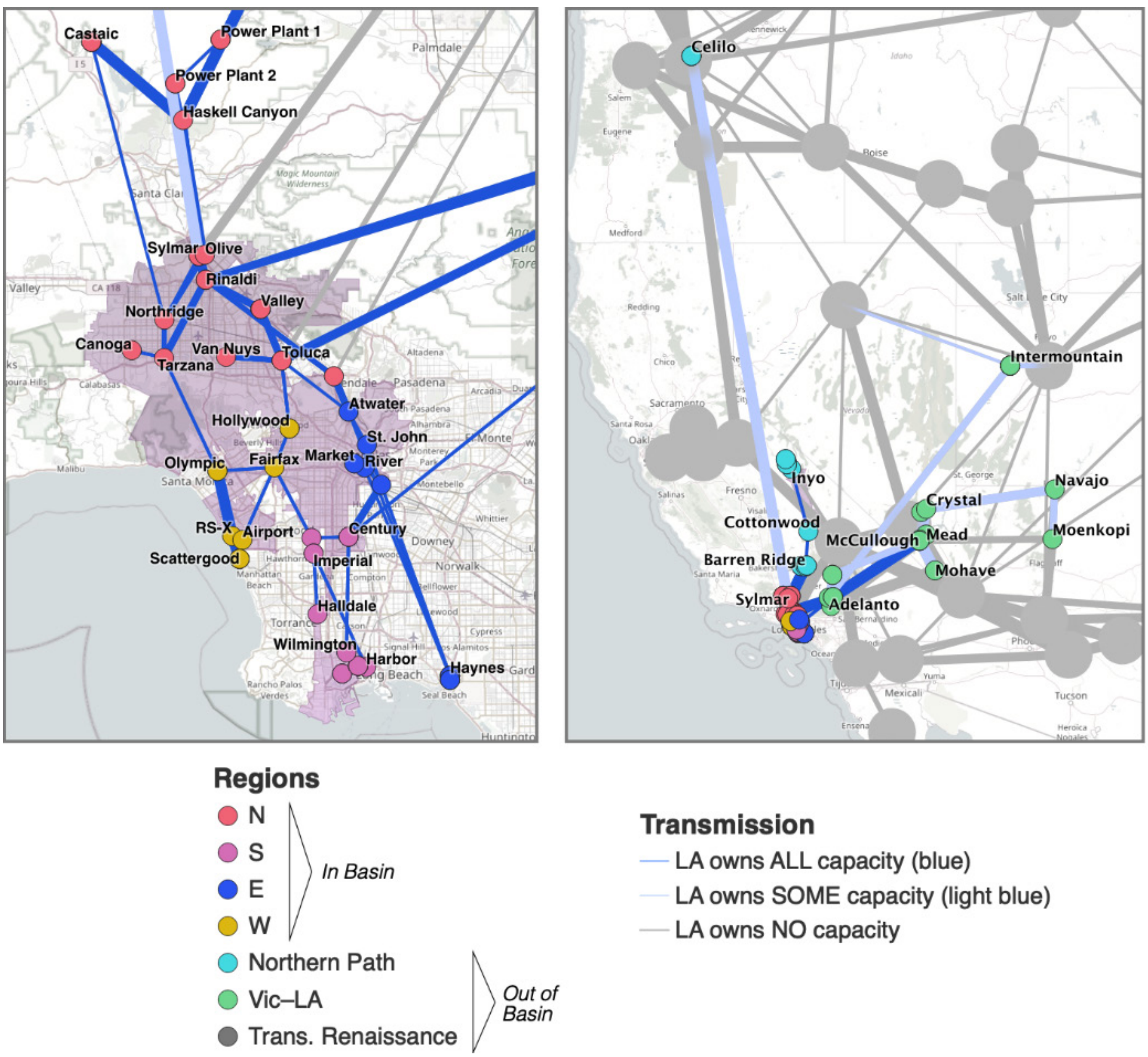

Figure 13. Map of the transmission network considered in RPM and PLEXOS (including the zonal representation of other BAs, in gray) and the six simplified regions considered in PRAS

The capacity expansion, production cost, and power flow (discussed later) modeling all use the 2012 weather year as a basis. This weather year determines renewable resource profiles and is used as an input the load modeling (to capture temperature, humidity, and other impacts on load). However, interannual variability in solar and wind resources, as well as load, can lead to substantial differences in the operations of a system, and if systems are not designed to be robust to such variability, a low wind or a low solar year could lead to instances of unserved energy. To ensure that the identified systems are robust to interannual variability in variable renewable resources, we the PRAS using 7 years of historical weather data.[18] Hourly profiles for each of the 7 years for wind, utility-scale PV, distributed PV, and CSP technologies were obtained from NREL's Wind Integration National Dataset (WIND) Toolkit[19] and National Solar Radiation Database (NSRDB),[20] processed through NREL's System Advisor Model[21] with specific technology assumptions to generate capacity factor profiles.[22] We use the same load year (2012, adjusted for climate change) paired with all 7 years of weather data.

Summary of Assumptions—Resource Adequacy

- In addition to techniques employed in capacity expansion modeling, the study uses the resource adequacy tool PRAS to evaluate the load shortfall risk for each of the capacity expansion projections. The tool calculates probabilistic risk metrics by simulating system balancing under a range of random generator outage conditions to assess the expected impact of these outages on meeting demand.
- The reliability metric target used for the bulk system in LA100 is a probabilistic expectation of 24 hours of lost load over 10 years. On an energy basis, which is a preferred approach in the presence of energy storage, 0.01 kWh per MWh of energy demand (0.001%, or 10 ppm) is being used as a reference point.
- PRAS is run for the 2030 and 2045 RPM model years using wind and solar generation profiles for multiple historical weather years (2007–2013) to evaluate impact of renewable resource variability.

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[18] Michael Milligan, Bethany Frew, Eduardo Ibanez, Juha Kiviluoma, Hannele Holttinen, Lennar Soder, "Capacity Value Assessments of Wind Power," *Wiley Interdisciplinary Reviews: Energy and Environment* 6:1–15 (2017), https://doi.org/10.1002/wene.226.

[19] Caroline Draxl, Andrew Clifton, Bri-Mathias Hodge, and Jim McCaa, "The Wind Integration National Dataset (WIND) Toolkit," *Applied Energy* (151): 355–366 (August 2015), https://doi.org/10.1016/j.apenergy.2015.03.121.

[20] Manajit Sengupta, Yu Xie, Anthony Lopez, Aron Habte, Galen Maclaurin, and James Shelby, "The National Solar Radiation Database (NSRDB)," *Renewable and Sustainable Energy Reviews* 89: 51–60 (June 2018). https://doi.org/10.1016/j.rser.2018.03.003.

[21] Nate Blair, Nicholas DiOrio, Janine Freeman, Paul Gilman, Steven Janzou, Ty Neises, and Michael Wagner, *System Advisor Model, SAM General Description (Version 2017.9.5)* (NREL 2018), NREL/TP-6A20-70414, https://www.nrel.gov/docs/fy18osti/70414.pdf.

[22] Galen Maclaurin, Nick Grue, Anthony Lopez, and Donna Heimiller, *The Renewable Energy Potential (reV) Model: A Geospatial Platform for Technical Potential and Supply Curve Modeling* (NREL 2019), NREL/TP-6A20-73067, https://www.nrel.gov/docs/fy19osti/73067.pdf.

1.6 Bulk Power Flow and Stability

A bulk power flow and stability study expands on PCM analysis to provide a more detailed examination of transmission system reliability. It tests the ability of a power system to respond to a real-time disturbance such as an unplanned generator or transmission line outage (contingency event).

Power flow and stability studies model real and reactive power flow, fault tolerance, and contingency response over very short timeframes that correspond to periods of system stress. Evaluation of costs and economics is not usually a component of this type of reliability analysis.

Several industry-accepted, commercially available power flow and stability analysis models are available. Many power system operators already use these types of models to inform power system planning. NREL used the GE Positive Sequence Load Flow (PSLF) model. Figure 7 illustrates the flow of the power flow and stability analysis step within the bulk system modeling effort. Figure 14 shows the key steps followed in the power flow and stability analysis task.

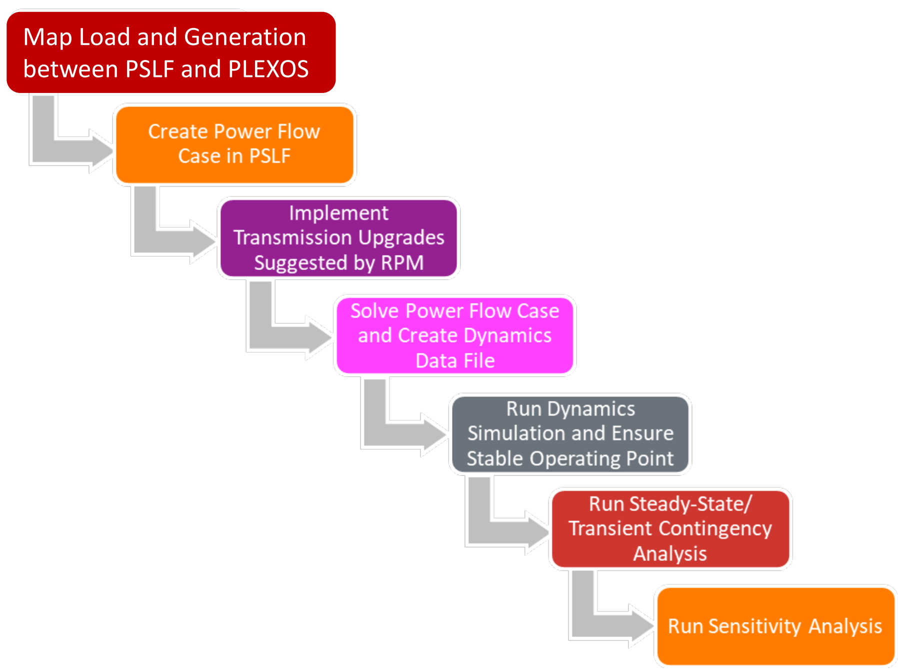

Figure 14. Key steps of the power flow and stability analysis task

This study used established PSLF models of the WECC system obtained from LADWP, including detailed data on transmission/distribution lines, transformers, loads, etc. Based on results from the PCM, we selected the hour with the highest total bus load (i.e., net of positive load left at all load buses after subtracting co-located generation) for 2030 SB100 – Stress and 2045 Early & No Biofuels – High scenarios to undergo detailed power flow and stability analysis with PSLF. Simulations consider contingencies such as the loss of the largest generating unit or major transmission lines in the system to evaluate the LADWP power system against the applicable reliability criteria. Three sensitivities were also performed for each of the two scenarios. These sensitivities attempt to identify system constraints under high northern imports, monsoon, and high flow conditions on the Victorville-LA (VIC-LA) path. Only steady-state power contingency analysis was performed for the sensitivities.

PSLF-based power flow analysis was also performed to evaluate the feasibility of power delivery in selected long-duration outage dispatches developed in PLEXOS for the year 2045 for the Early & No Biofuels – High scenario.

This task is primarily a validation task; results from power flow and stability simulations provide feedback to refine the production cost and/or capacity expansion models. Power flow and stability simulations can expose weaknesses in the system that may need to be addressed by changing scenario assumptions, adding transmission or generation capacity, and/or adjusting grid operations. The costs of significant upgrades identified in this step are considered in the final scenario results.

Summary of Assumptions—Bulk Power Flow Modeling

- The study uses a power flow and stability analysis tool, PSLF, to validate the reliability of the capacity expansion projections by ensuring reliability criteria are satisfied in normal operations and after events such as faults, and generation or transmission outages.
- The study evaluates system stability for the time instant with highest likelihood of reliability criteria violations (highest bus load in LADWP) in two analysis years—2030 and 2045.
- Although most other LA100 models are employed across all scenarios, PSLF is employed for only two scenarios (2030 SB100 –Stress and 2045 Early & No Biofuels – High). Power flow and stability analysis of the highest bus load hour of the 2030 SB100 – Stress scenario enables us to evaluate the impact of significant changes in the amount, location, and type of generation and loads on the reliability of the LADWP power system in the near term. Early & No Biofuels, which does not allow thermal generation including biomass, presents the most challenging scenario in terms of in-basin dispatchable capacity in 2045 and helps to identify the resources and upgrades required to reliably operate the LADWP system in the long term.
- To the extent possible, changes in load and generation of adjacent areas most tightly coupled with LADWP (Arizona, Nevada, Southern California Edison, Bonneville Power Administration, and PacifiCorp East) are also made in the power flow cases before performing the steady-state and transient stability analyses. As a result, the impact of changing loads and resource mix in these areas on the reliability of the LADWP power system is analyzed to a limited extent. However, detailed power flow and stability modeling for these areas was outside the scope of this project, and there may be additional interactions between the LADWP transmission network and that of the rest of the Western Interconnection that could impact reliability.
- Because of the focus on LADWP's power system, we did not identify the upgrades required in the adjacent areas to ensure feasibility of power flows in these areas based on the RPM/PLEXOS defined load and generation mix. A complete Western Interconnection-wide power flow and stability analysis study that uses detailed network models of the entire WECC is needed to identify the impacts of changes in one region on the reliability of the other regions in the Western Interconnection.
- PSLF-based power flow feasibility evaluation of selected long duration outage dispatches developed in PLEXOS for year 2045 (Early & No Biofuels – High scenario) also help identify additional upgrades or changes in dispatch/resource mix that may be needed to meet LADWP's reliability criteria if such long-duration outages were to occur.

- The study assumes that inverter-based technologies such as wind and solar can provide voltage and frequency support to the grid (e.g., reactive power and primary frequency response). The study also assumes that RE-CTs have synchronous condenser capabilities (including clutched operation) to provide voltage and frequency support.
- The study relies heavily on the data and models provided by LADWP (e.g., power flow files, dynamics data, contingency definitions), which are appropriately modified for the scenarios analyzed based on the inputs received from RPM and PLEXOS.
- For any new generator or load that we add beyond the ones already available in the 2028 Heavy Summer (HS) data we received from LADWP, we used the dynamic models from the list of WECC models approved in May 2018.[23]

Appendix D provides additional detail on data sources for power flow and stability analyses.

[23] The dynamic models do not capture the full capabilities of inverter-based resources and there is active work to update the characterization of these resources.

2 Pathways to 100% Renewable Energy

2.1 How Is the Target Met? The Generation Mix

A broad range of options is available for LADWP to achieve a 100% renewable energy power system. Figure 15 and Figure 16 illustrate the progression of the generation mix from 2020 through 2045 across the suite of LA100 scenarios for both the Moderate and High load projections. As discussed earlier, we also simulate a LADWP 2017 Integrated Resource Plan (2017 IRP) using Moderate load electrification. This is included as a reference case and captures, as best as possible, the LADWP 2017 Strategic Long-Term Resource Plan *Recommended* Case. The 2017 SLTRP extends only to 2037, and thus the simulations of this scenario only extended through the solve year of 2035.

Across all the LA100 scenarios explored, wind and solar generation account for the majority (approximately 69%–87%, depending on the scenario) of total energy generation in 2045. The rest of the energy needs come from a variety of sources depending on scenario, including nuclear, hydropower, geothermal, renewably fueled combustion turbines, and natural-gas-fueled generation (which is only allowed in the SB100 scenario). Energy storage—in the form of batteries, pumped hydro, and long-duration hydrogen-based storage—also play a substantial role by shifting surplus energy to times of energy deficit.[24]

[24] Charging of storage is shown as negative generation, whereas discharge of the storage is shown as positive. The amount of the negative energy (charging energy) is equal to the difference between the load line and the total (non-curtailed) energy line.

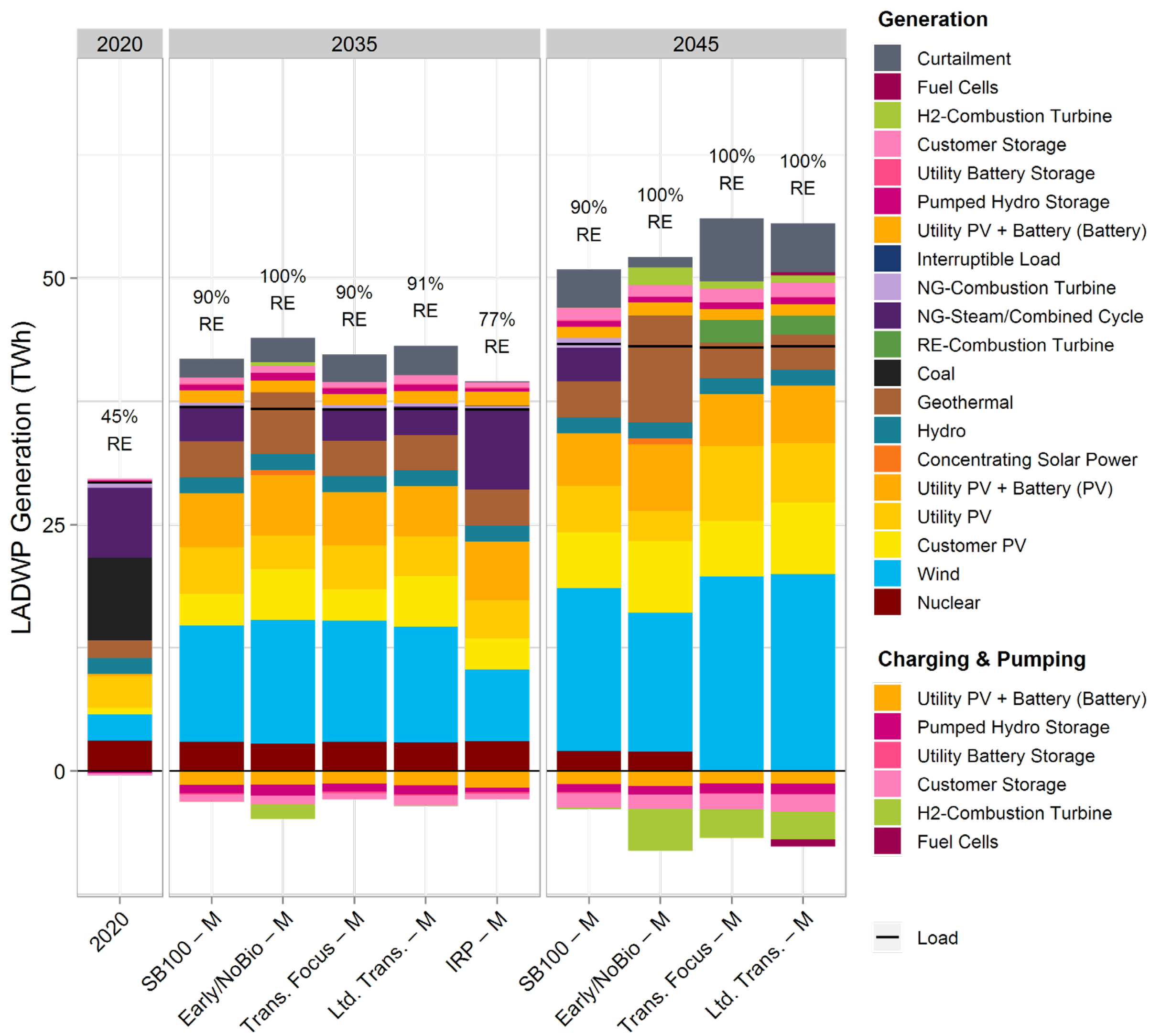

Figure 15. Annual generation mix for all Moderate load scenarios

The percent RE refers to percent of generation that is carbon neutral (renewable and nuclear). Negative values indicate the amount of electricity consumed by the plant (e.g., to charge a battery, pump hydro, or produce hydrogen fuel). Load (solid line) is customer electricity consumption exclusive of charging. Curtailment includes available energy that is curtailed to provide reserves.

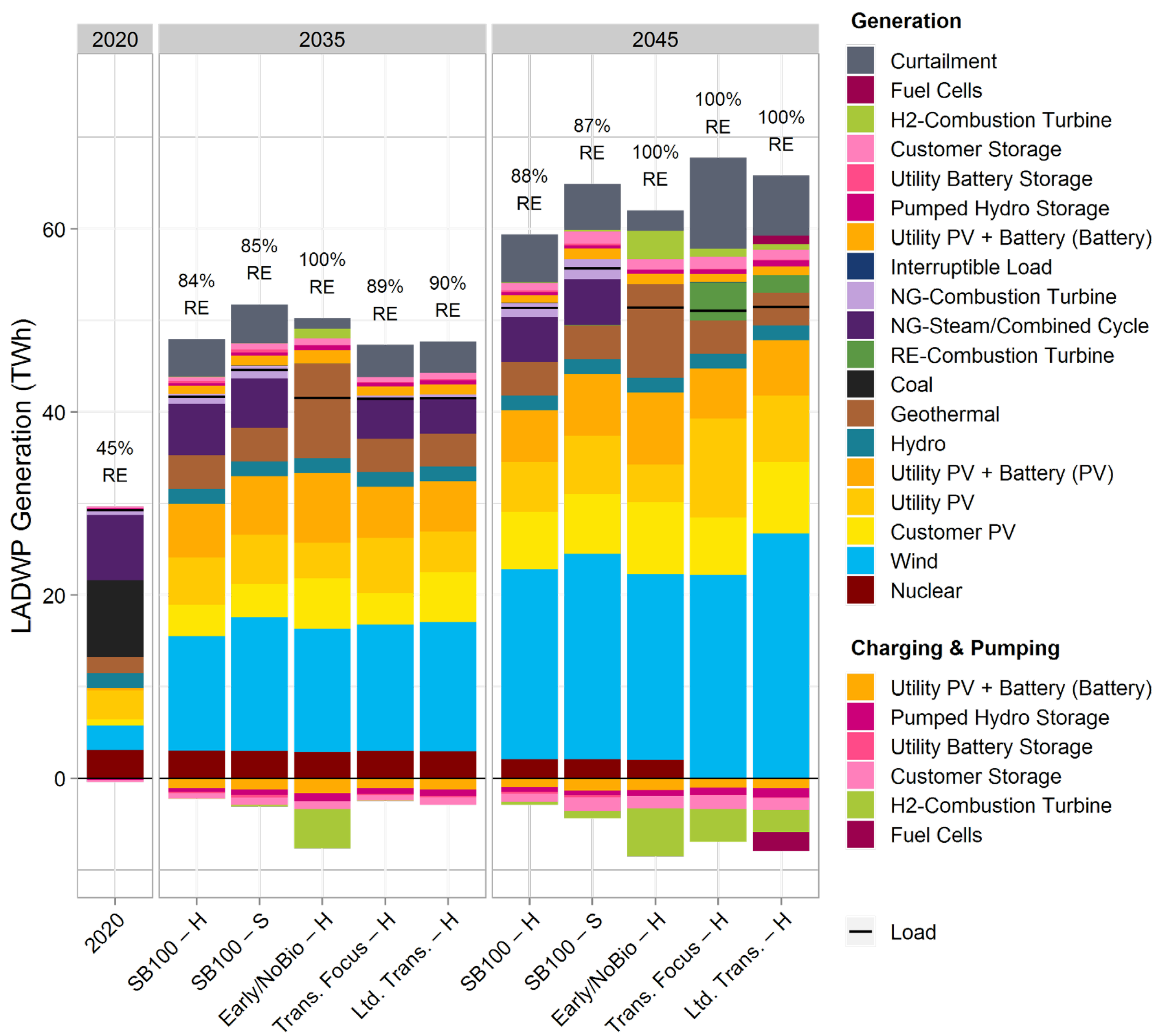

Figure 16. Annual generation mix for all High and Stress load scenarios

The percent RE refers to percent of generation that is carbon neutral (renewable and nuclear). Negative values indicate the amount of electricity consumed by the plant (e.g., to charge a battery, pump hydro, or produce hydrogen fuel). Load (solid line) is customer electricity consumption exclusive of charging. Curtailment includes available energy that is curtailed to provide reserves.

Figure 17 illustrates the location of the energy generation in the year 2045 for all scenarios (with 2020 shown for comparison). Much like today, most of the energy in the LA100 scenarios is derived from resources located outside the LA Basin, where wind and geothermal can be deployed, and the highest quality solar resources are located. In-basin generation includes customer (rooftop) PV, storage, as well as a critical amount of generation from “firm” or “dispatchable” capacity resources including natural gas or renewably fueled combustion turbines.

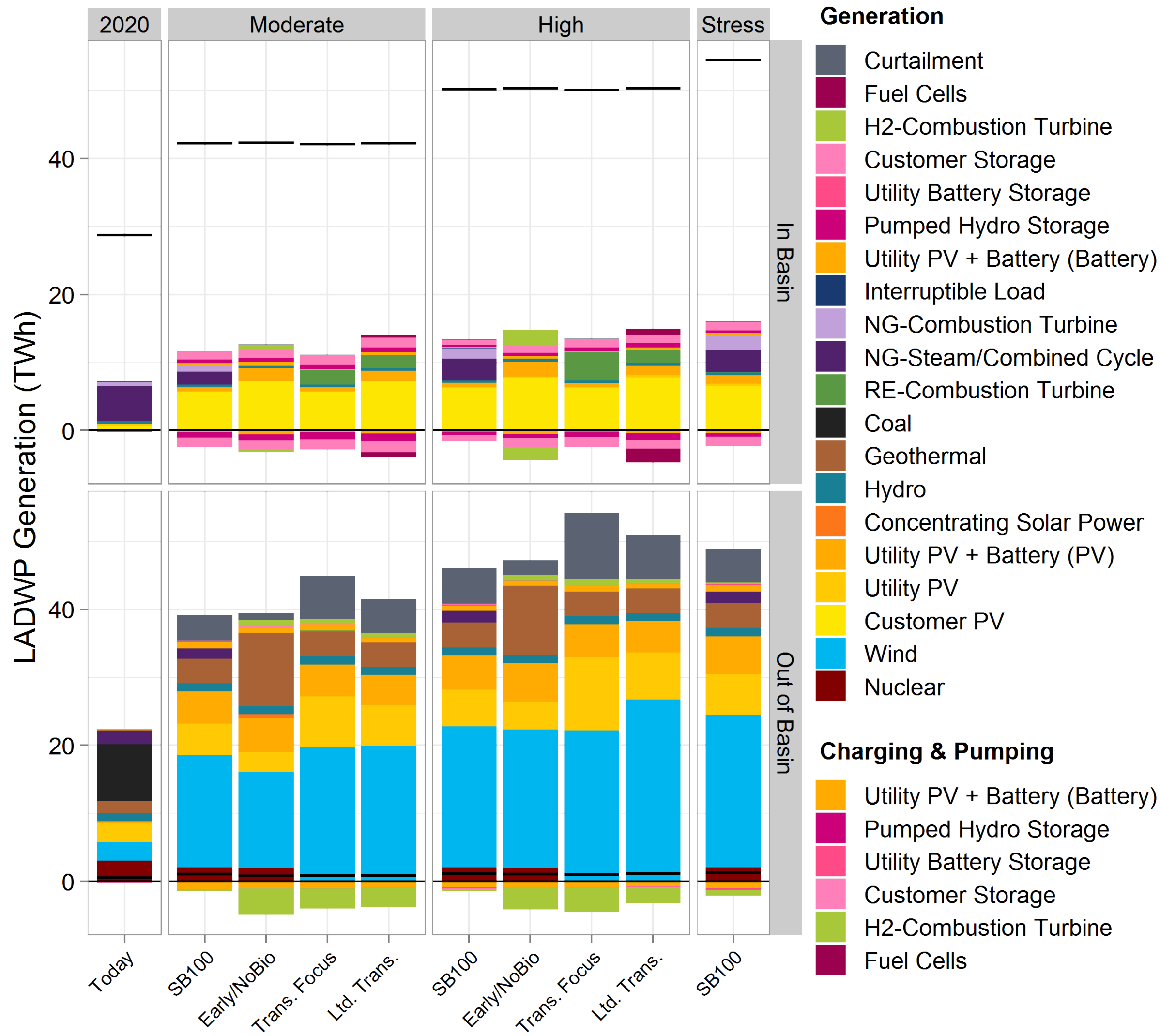

Figure 17. Annual generation by location and scenario in 2045

Negative values indicate the amount of electricity consumed by the plant (e.g., to charge a battery, pump hydro, or produce hydrogen fuel). Load (solid line) is customer electricity consumption exclusive of charging. Curtailment includes available energy that is curtailed to provide reserves.

An important consideration in high renewable energy scenarios is the ability to effectively match supply and demand, given that much of supply is weather dependent and varies by hour to hour and season by season. Figure 18 shows the monthly contribution of generation resources for two scenarios (SB100 – High and Early & No Biofuels – High) in the year 2045. Over both scenarios, renewable generation from wind, solar, geothermal, and hydro make up the large majority of energy needs throughout the year. However, during late summer, fall, and early winter, reduced output of wind and solar coincides with the periods of highest load (August, September, October). To augment wind and solar during these periods, dispatchable generation (from natural gas-fired generation in SB100 and hydrogen combustion turbines in Early & No Biofuels) increases. Given that hydrogen combustion turbines represent a long-duration storage technology with hydrogen produced with surplus generation, stored, and subsequently combusted to generate electricity, in the Early & No Biofuels scenario, hydrogen is produced (indicated by negative generation on the y-axis) during the spring months when wind and solar resources are of highest quality, and subsequently consumed during the late summer, fall, and winter.

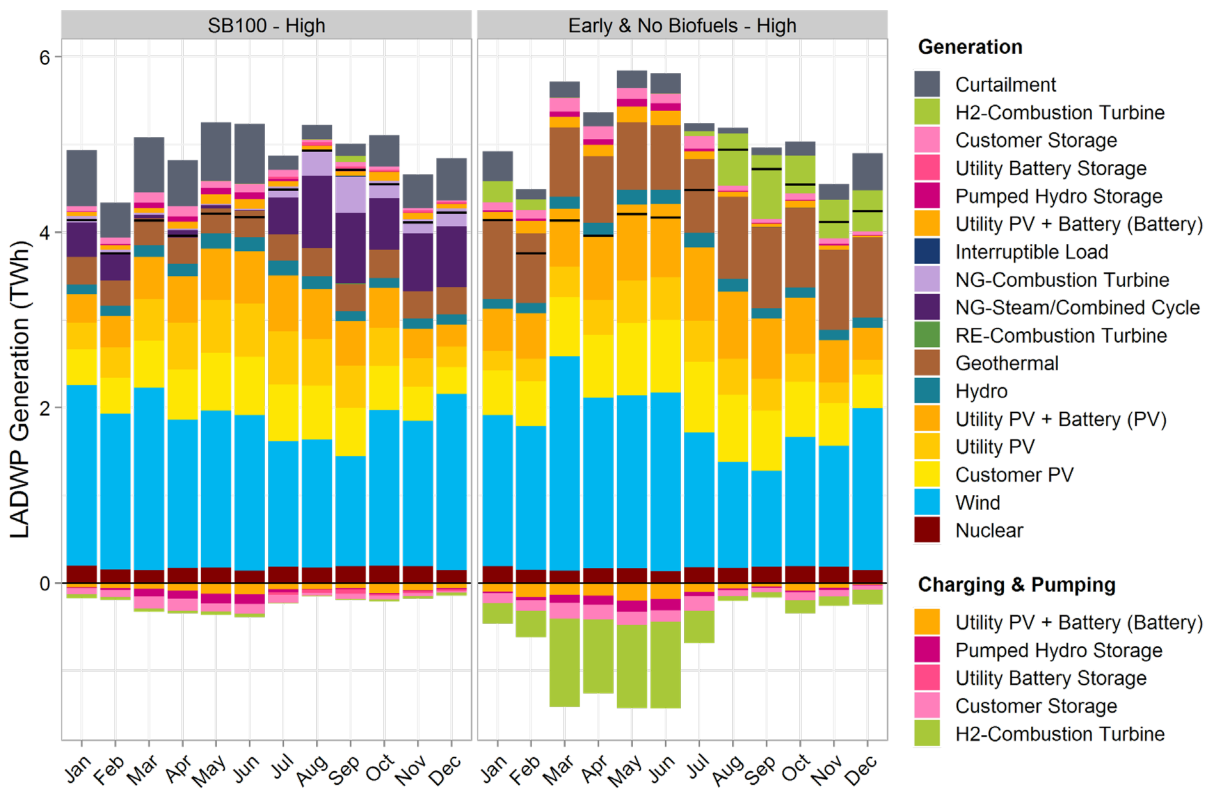

Figure 18. Monthly generation mix for SB100 – High (left) and Early & No Biofuels – High (right) in 2045

Negative values indicate the amount of electricity consumed by the plant (e.g., to charge a battery, pump hydro, or produce hydrogen fuel). Load (solid line) is customer electricity consumption exclusive of charging. Curtailment includes available energy that is curtailed to provide reserves.

Seasonal matching of supply and demand is essential when there are months of relatively low output from wind and solar. Of course, daily matching of supply and demand is also an important consideration in 100% renewable energy scenarios. Figure 19 and Figure 20 illustrate the hourly generation mix for four example days in SB100 – Stress and Early & No Biofuels – High for the year 2045. Figure 19 shows how hourly load is met by generation. The plot shows three load lines. First, the thin solid line shows the original hourly demand. The dashed line shows the load shape resulting from demand response resources (largely electric vehicle charging load) shifting load from one period of the day to another. Finally, the thick solid line with filled dots includes demand response as well as consumption for charging batteries, which indicates the fully shifted and *total hourly load* that generation must meet.

In the SB100 scenario, load is matched by relying on significant wind, especially in the winter months, and solar throughout the day. Flexible loads are shifted to periods of high solar output. Storage and the natural gas generators are used to fill in the gaps. The SB100 – Stress scenario achieves 87% renewable energy contribution and will sometimes run for days without using any natural gas. However, the system still relies heavily on the gas fleet to provide reliable service during periods of high demand and low renewable output. Without natural gas, the Early & No Biofuels scenario (Figure 19) relies more on geothermal as an additional source of both energy and firm capacity, on diurnal storage (with less than 12 hours of duration) for daily energy shifting, and on long duration storage in the form of hydrogen-fueled combustion turbines (another form of firm capacity) to accommodate the seasonal mismatch in supply and demand and to help serve load during times of low wind and solar output and/or high load conditions.

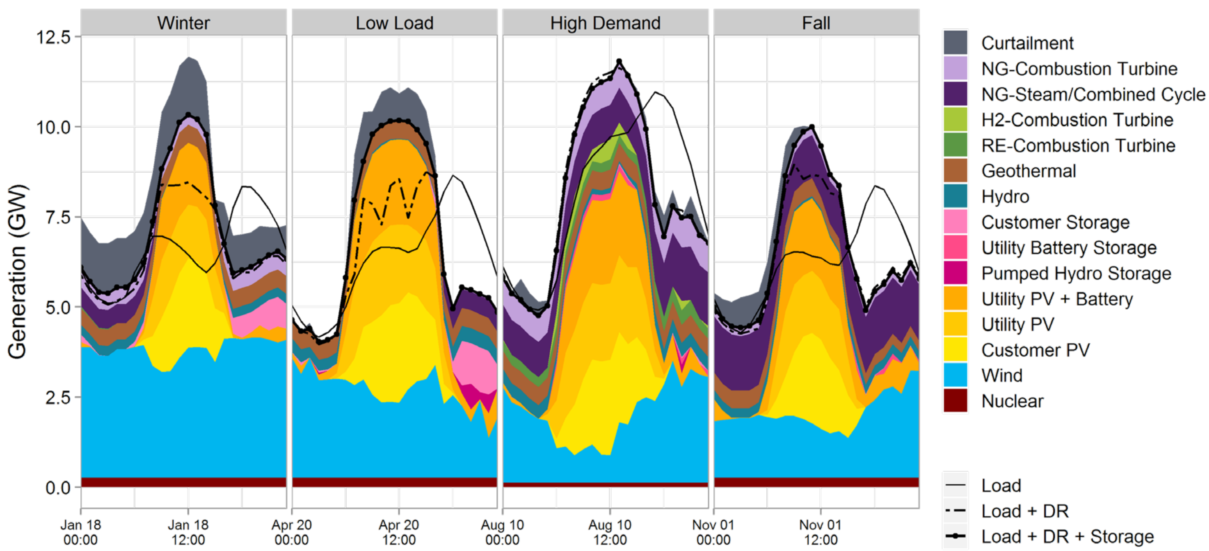

Figure 19. Hourly generation dispatch for SB100 – Stress in 2045 for four example days in 2045—in January (winter), April (low load), August (high demand), and November (fall)

Curtailment includes available energy that is curtailed to provide reserves.

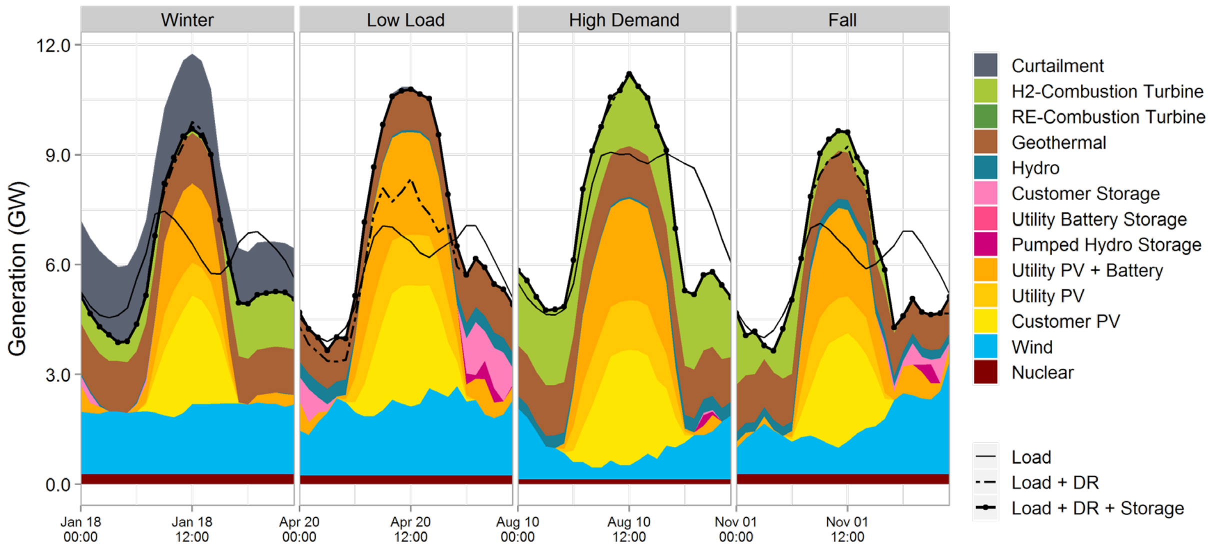

Figure 20. Hourly generation dispatch for Early & No Biofuels – High in 2045 for four example days in 2045—in January (winter), April (low load), August (high demand), and November (fall)

Curtailment includes available energy that is curtailed to provide reserves.

2.2 What Gets Built

2.2.1 Generation and Storage

LA100 expands the LADWP generation fleet with new renewable resources and new in-basin capacity needed to ensure reliability.

The capacity mix (Figure 21) looks very different than the overall generation mix. As in fossil-dominated systems, power systems need extra capacity to be available during times of high load, such as hot summer days, and when other plants are not available due to scheduled outages for maintenance or unexpected generation or transmission failures. To ensure sufficient capacity is available, the LA100 scenarios rely on large amounts of peaking capacity that do not provide much energy but are available to provide energy during these infrequent times of stress—this helps ensure reliability of the system. These plants include natural-gas-fired plants in SB100, and CTs using renewable-derived fuels (e.g., hydrogen, liquid or gaseous biofuels, synthetic natural gas—our study assumes only biofuel or hydrogen) in all the scenarios.

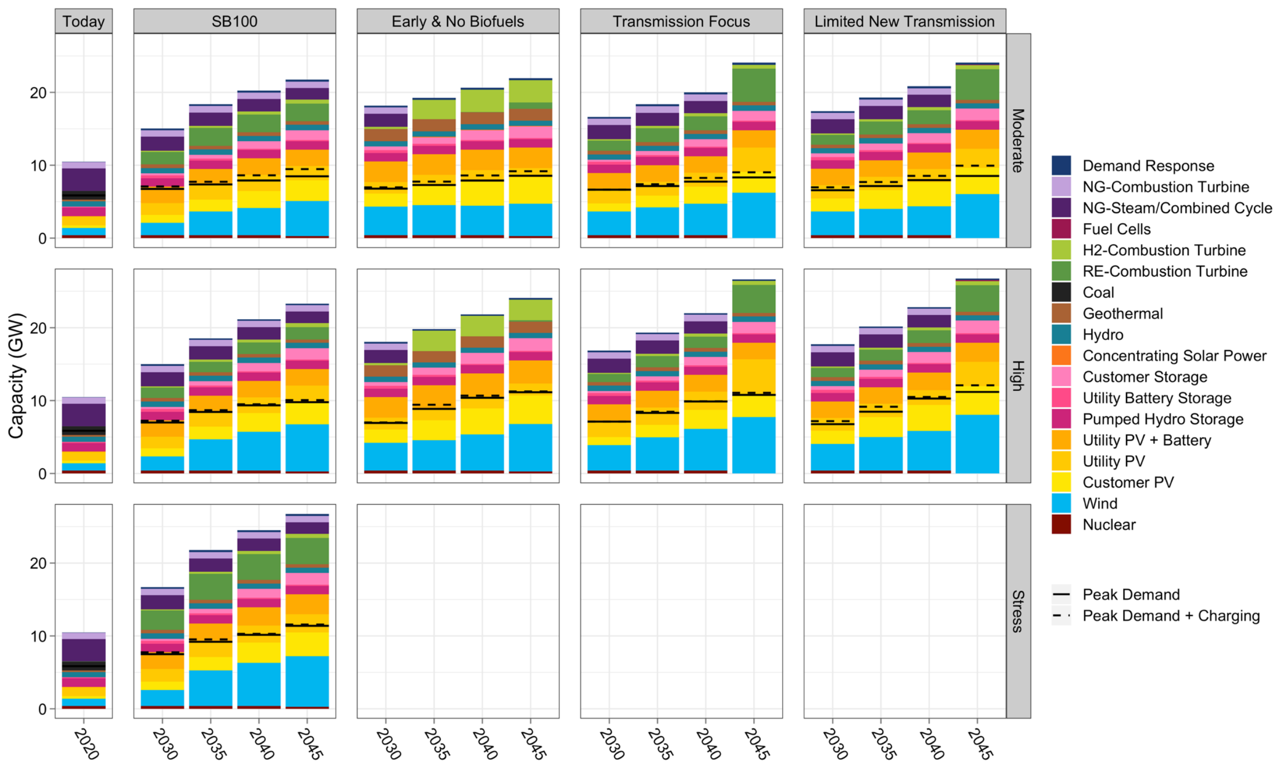

Figure 21. Capacity mix over time

Top row shows Moderate load projections for each scenario; middle row shows High Load scenarios; bottom row shows SB100 – Stress load projection.

Utility PV + battery assumes co-located solar and storage with shared loosely DC-coupled inverter capacity. Capacity represented is the capacity of the inverter (i.e., the maximum output). The size of the solar relative to the battery is chosen by the model, but typically is 2:1 (e.g., 10 MW PV + battery has a 10 MW solar array with 5 MW of battery storage).

Overall capacity (supply) on the system grows over time due to the increases in electricity demand (peak load) from present day to 2045 (approximately a 43% increase in peak under the High load projections). In addition, providing a given amount of energy with wind and solar assets will typically require substantially more nominal capacity than with fossil assets due to the lower capacity factors at which wind and solar resources operate. As a result, even under a scenario with zero load growth, if there is a transition to greater contribution from wind and solar, total capacity will typically grow. This effect also contributes substantially to the observed growth in these scenarios.

Figure 22 illustrates the installed capacity for each scenario by location (in basin vs. out of basin). While a large fraction of the energy is provided by out-of-basin resources, the capacity is distributed more evenly. This is due to the fact that most of the gas and renewably fueled peaking plants are located in the LA Basin to ensure reliable service, providing energy during periods of low wind and solar output, and acting as insurance against failures of transmission lines that carry out-of-basin renewable energy into the LADWP service territory.

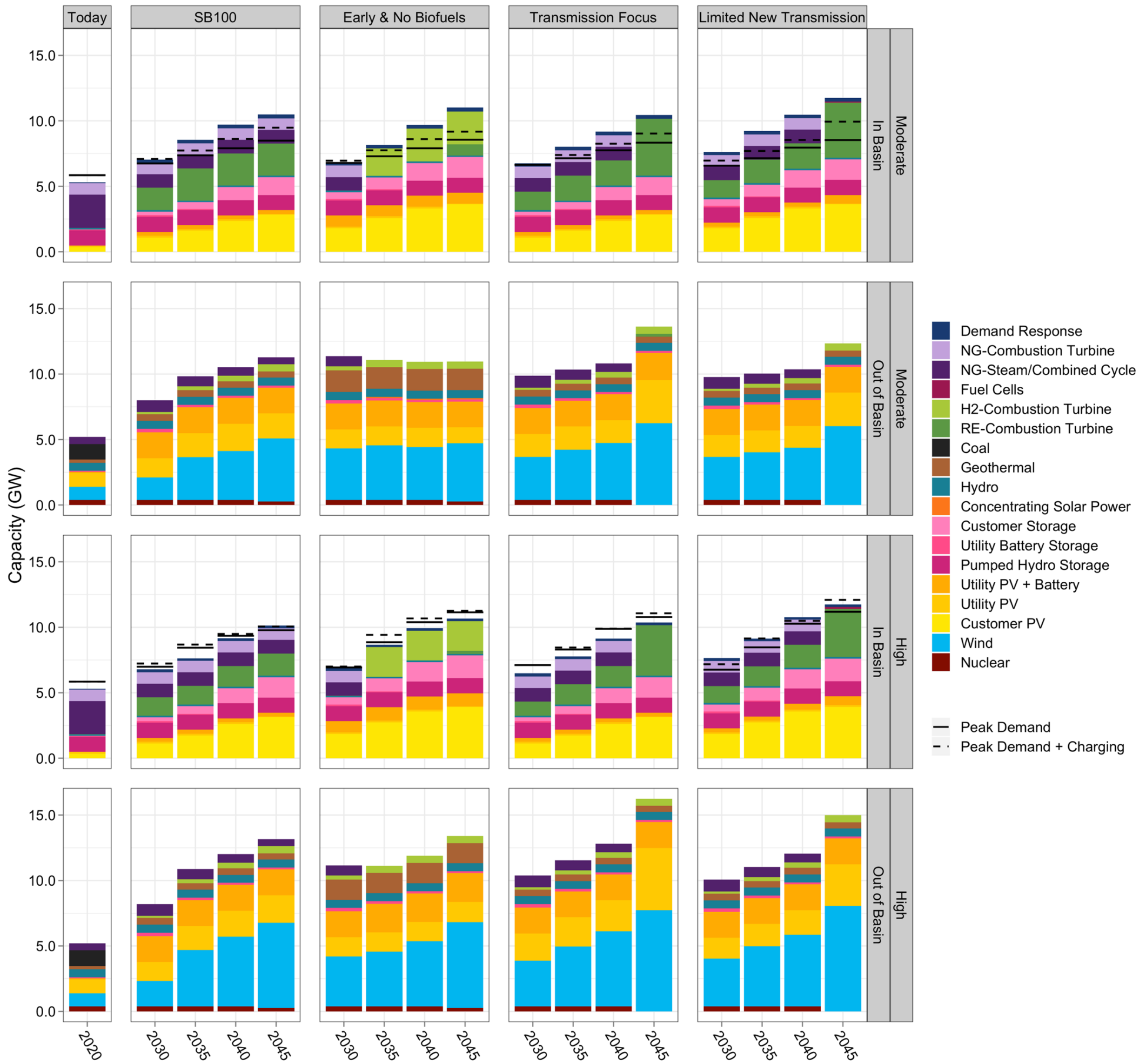

Figure 22. Where capacity gets built

The top two rows show Moderate load projection split into in- and out-of-basin capacity; the bottom two rows show High load projection split into in- and out-of-basin capacity.

2.2.2 Transmission

Transmission is an important asset for LADWP throughout the study period. Particularly by 2045, when the total generation from renewable resources located outside the LA Basin approaches nearly double the generation from all out-of-basin resources in 2020 in some scenarios, transmission is essential for moving power to load. While not all scenarios allow expansion of the transmission network beyond currently planned upgrades, all scenarios that allow such expansion do upgrade the system within the LA Basin. Given that energy from outside the basin is injected into the urban area at effectively four main points on the northern and eastern edges of the basin, these within-basin upgrades serve to increase the ability to move that energy from the point of receipt to the point of use within the basin. These upgrades also help to ensure that energy produced from the in-basin firm capacity resources can be transmitted to the point of use. Under the Early & No Biofuels scenario, the ineligibility of biofuels leads to an increased need for transmission to connect out-of-basin resources. Under the Transmission Focus scenario, the DC transmission backbone (consisting of a DC line from outside to inside the LA Basin and additional within-basin DC ties to three key transmission nodes) is assumed to be constructed, which comprises the bulk of new transmission and alleviates the need for other substantial upgrades. Figure 23 shows the transmission capacity installed by scenario. These additions include upgrades of existing lines and transformers as well as new transmission corridors, including existing plans for transmission upgrades communicated by LADWP as of June 2020. It is important to note that the planned transmission upgrades include aspects of transmission maintenance that are not captured within RPM. We expect such maintenance to be required in future years, but these estimates are not included in the figure below after 2030. While the DC backbone of the Transmission Focus scenario dwarfs the capacity installed in all other scenarios, in-basin upgrades are an important aspect of all scenarios, with an additional 50–640 MW upgraded by 2045 for all scenarios allowing new transmission builds. This capacity represents a range of upgrades, including reconductoring and transformer upgrades at receiving and switching stations.

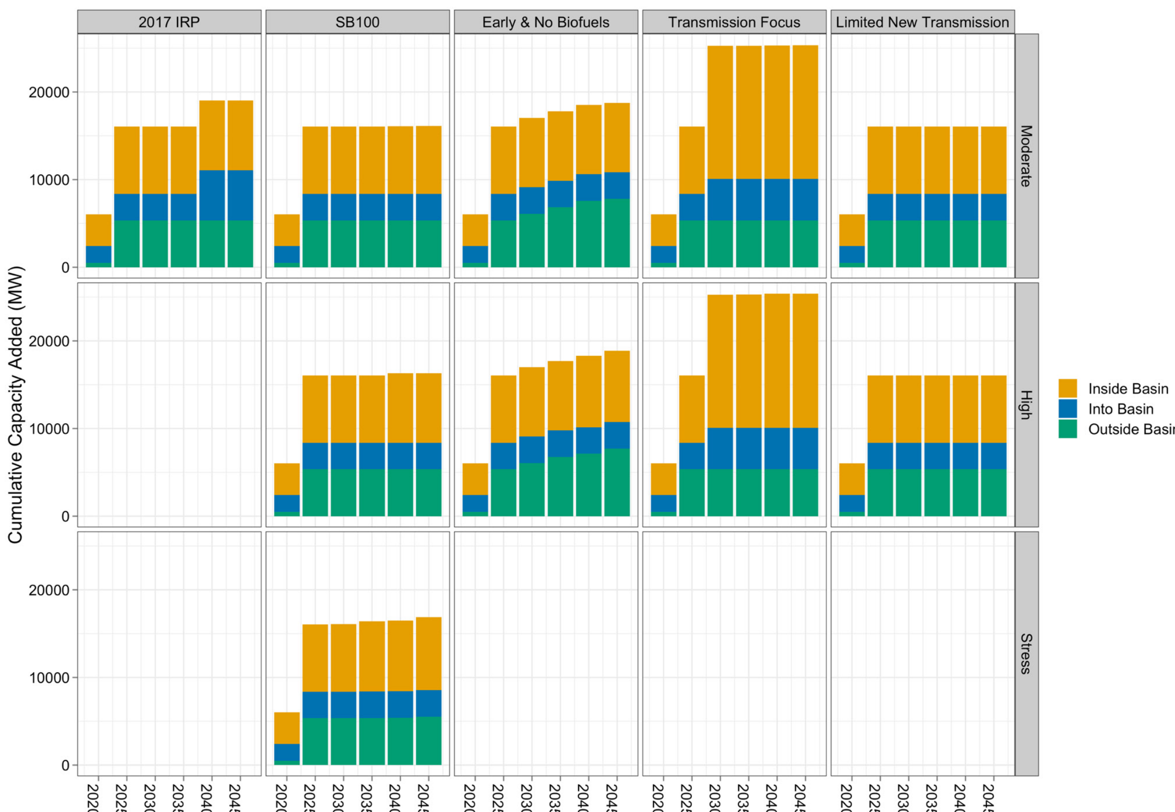

Figure 23. The combined capacity of inside-basin, into-basin, and outside-basin transmission upgrades added through 2045 for all scenarios and load projections, including existing plans for transmission, firm as of June 2020 and communicated by LADWP

The Limited New Transmission scenario does not allow transmission upgrades beyond currently planned projects, and hence that scenario illustrates the baseline for additional upgrades in other scenarios.

2.3 Looking Deeper: Wind, Solar, and Storage—How Much, When, and Where

Solar PV (both with and without co-located battery storage) and wind resources are deployed at a rapid pace and account for a growing share of total energy needs in all LA100 scenarios. Figure 24 shows the total installed wind and solar capacity for each scenario through 2045.

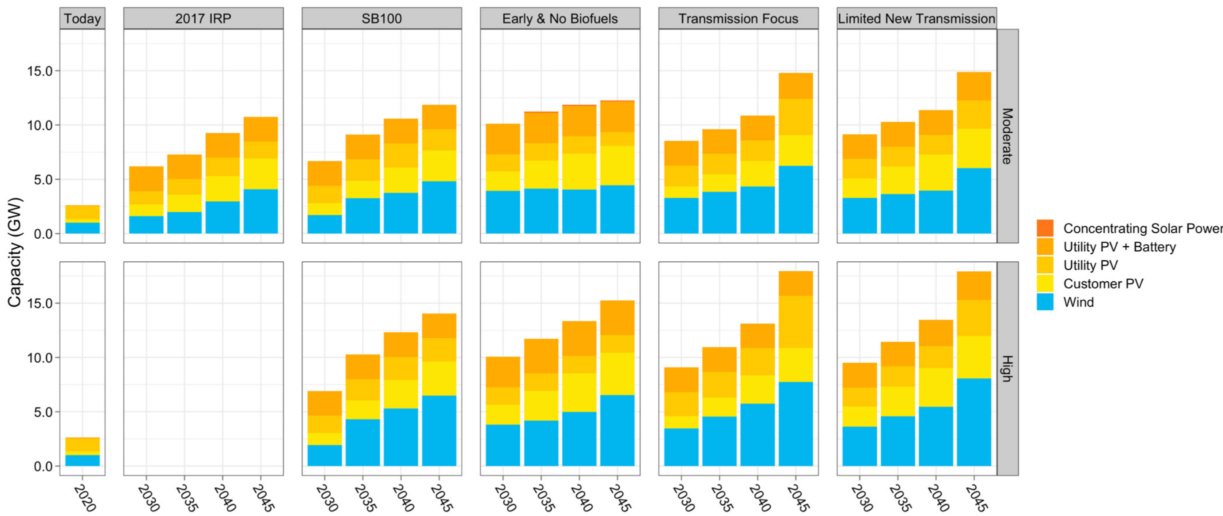

Figure 24. Wind and solar capacity in each scenario

Top row shows Moderate load projections, bottom row shows High load projections.

Growth in *wind* capacity from 2021 to 2045 ranges from 3–5 GW in the Moderate projections and 5–7 GW in the High projections, corresponding to average annual net additions of 120–290 MW per year. While all scenarios build significant new wind, the modest difference in wind growth across the scenarios can be attributed to the contribution of wind toward peak demand (i.e., its capacity credit). Wind has a much higher capacity credit than solar and maintains its capacity credit at higher penetrations, whereas the ability of solar to contribute to firm capacity declines sharply. The Transmission Focus and Limited New Transmission scenarios show the highest levels of wind deployment. Under both scenarios, the nuclear capacity at Palo Verde Generating Station is assumed to be retired, which creates an increased need for energy and capacity services—both of which the additional wind helps to serve. Furthermore, under the Transmission Focus scenario the DC backbone alleviates limitations on the ability to transmit energy from distant out-of-basin wind resources and can therefore more easily utilize those resources. However, the Limited New Transmission scenario does not allow transmission builds beyond those already planned, so it is counterintuitive how further out-of-basin wind could be deployed. Examining the location of solar resources provides further insight: although both scenarios reach approximately 9 GW (under Moderate load projections) of combined PV resources split between out-of-basin and in-basin resources, the Limited New Transmission scenario has over 1 GW more capacity located in the LA Basin. This means that those in-basin resources are not occupying capacity on the out-of-basin and out-to-in basin transmission network, thereby freeing up more transmission capacity for wind resources.

Growth in total *solar* resources, including utility-scale PV, PV with co-located battery storage, customer rooftop PV, and concentrating solar power (CSP), ranges from 4.5–6 GW in the Moderate projections and 5–8 GW in the High projections, corresponding to average net annual additions of 180–290 MW per year. Of this new capacity, about 40% is assumed to be customer procured based on the methodology described in Chapter 4.

Although in-basin solar has the advantage of being more resilient to transmission congestion and outages, most LADWP-procured solar in the LA100 study is built out of basin due to lower costs and maximizing use of existing and new transmission resources. All scenarios assume that customers build 2.8–3.9 GW of rooftop solar by 2045 (see Chapter 3 for details). Although technically eligible locations within the city for ground-mount and other utility-scale solar could support an additional 4.8 GW of PV at a levelized cost of less than $100/MWh, the LA100 scenarios build only a fraction of this potential.

The large growth in wind and solar capacity requires that a geographically diverse set of resources are used, particularly for wind. The map in Figure 25 shows the distribution of capacity resources by type and size in 2045 for each of the High projections. Each cluster shows the general location of where the resources are connected to the bulk transmission network. For solar and wind resources outside of the LA Basin, facilities may be relatively distant from the interconnection point. Solar plants are located both within and near to the LA Basin, with in-basin PV capacity predominantly made up of customer-adopted PV systems, and out-of-basin capacity largely utility-scale PV + battery facilities. The map inset shows that wind plants are relatively distant from LA: new wind capacity is located in Utah and Wyoming and interconnected through the IPP switching station and associated transmission infrastructure. Smaller amounts of wind capacity are sited closer to LA at sites in California and Nevada.

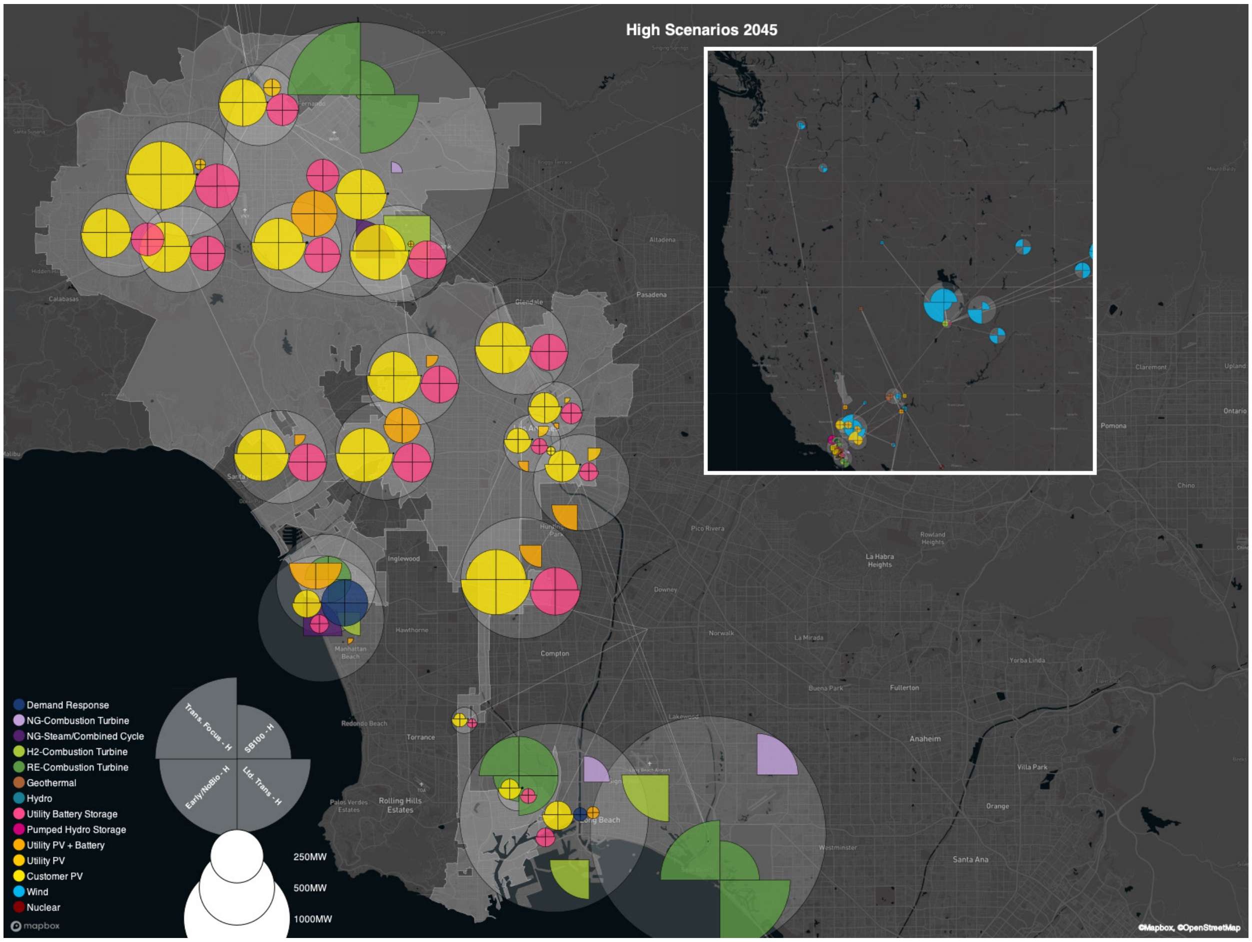

Figure 25. Map showing the interconnection location, type, and capacity of generation resources in 2045 across all four scenarios for the High projections

Each scenario is represented in one quadrant.

Wind and PV technologies represent the lowest-cost sources of renewable energy, so it is cost optimal to pursue rapid deployment of these technologies to meet renewable energy targets. However, given the variable profile of wind and solar assets, there reaches a point at which the value of further deployment greatly declines due to growing rates of curtailment and decreasing capacity credit. Energy storage is key to helping LADWP make the most of wind and solar assets by shifting surplus energy from mid-day to evening, nighttime, and morning hours.

Figure 26 shows the diurnal (4–12 hour) storage resources (dedicated battery, pumped hydro, and the battery portion of PV + battery systems) that are deployed and leveraged to shift surplus generation from midday to evening, night, and morning hours. Total 4- to 12-hour storage capacity in 2045 ranges from just under 4 GW to approximately 4.5 GW across scenarios. While the model was able to choose between 4- and 8-hour battery options, all installed battery capacity had four hours of storage, both stand-alone and as part of a coupled PV + battery system. Overall, diurnal storage increases utilization of renewable resources by 7%–12% across scenarios in 2045.

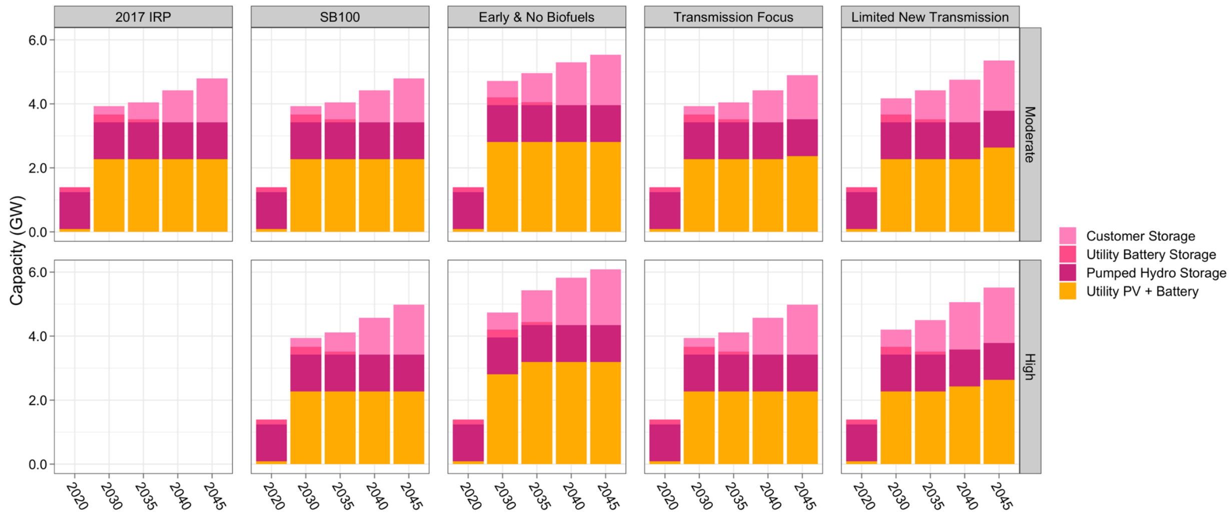

Figure 26. Diurnal storage capacity

Utility PV + battery capacity in this figure includes only the capacity of the battery portion of the system.

Typical utilization of the storage assets can be seen in Figure 27, which shows hourly dispatch for a set of representative days in 2045 under the SB100 – Moderate scenario. Charging of storage assets (combined with shifted load) can be seen during the daylight hours—creating a new and more extreme peak midday. This allows for the use of surplus PV generation to charge the storage assets and meet the shifted load demands. In the evening, night, and morning hours when PV generation is unavailable, battery storage (bright pink), the battery component of PV + battery systems (darkest yellow), and the pumped hydro storage capacity (magenta) are dispatched to meet load.

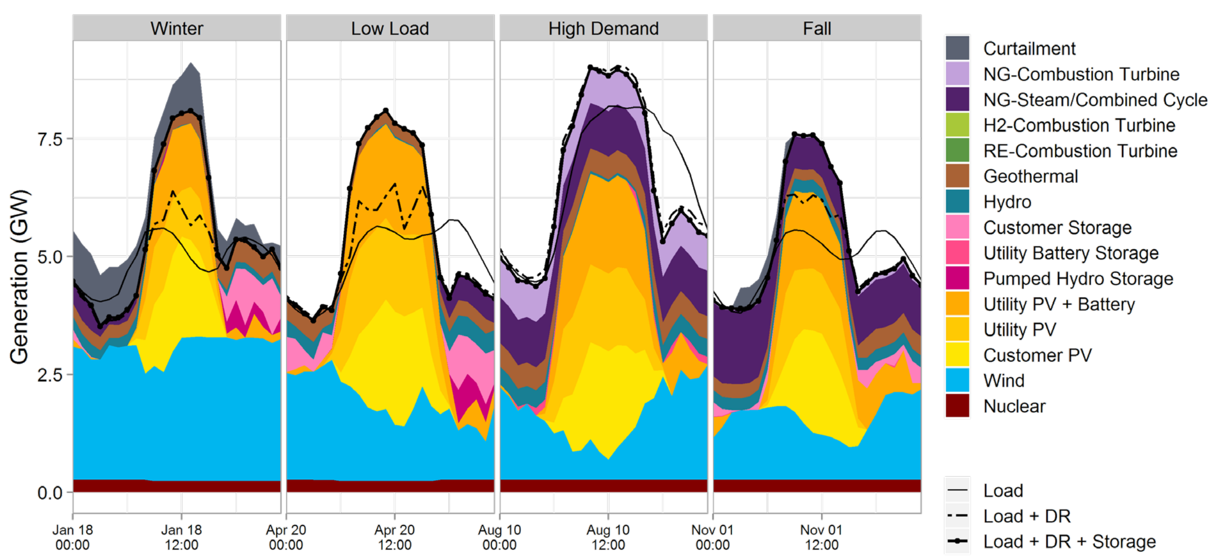

Figure 27. Hourly dispatch across a range of representative days in the SB100 – Moderate scenario (2045)

2.4 Looking Deeper: The Role of Firm Capacity and Seasonal Storage

New in-basin firm capacity—power plants that can come online within minutes and run for hours to days—contribute to the least-cost options to maintain reliability at 100% renewable energy. Procuring such resources will likely require LADWP to employ new renewable fuels, such as biofuels, biogas, and hydrogen, the technologies to convert them into electricity, and the associated infrastructure to store and transport such fuels.

Text Box 2. Firm Capacity Resources in the LA100 Study

We define a firm capacity resource as any technology that has a capacity credit (or dependable capacity rating) that is constant with system composition—irrespective of the mix of technologies and load patterns, the firm capacity rating of the resource is the same. Other resources, including any variable resource generation technology (such as wind and solar), storage resource with durations in the range of ~1 to ~12 hours, and demand response resources have dependable capacity ratings that vary with system configuration. For example, as the share of solar generation as a fraction of total load increases, its dependable capacity rating or capacity credit drops.

Conventional thermal generators, including coal steam, natural gas combined-cycle, natural gas combustion turbines, and nuclear technologies are all examples of firm capacity assets that utilize non-renewable fuels (fossil fuels and uranium). Renewable firm capacity technology options considered under the LA100 scenarios include renewably fueled combustion turbines (RE-CTs) that are assumed to use a market-purchased renewable fuel, two hydrogen-based long-duration storage technologies—hydrogen-fueled combustion turbines (H_2-CTs) and hydrogen fuel cells—both assumed to include infrastructure to self-produce and store hydrogen as ammonia, as well as geothermal, concentrating solar power (CSP) with thermal energy storage and renewable fuel backup, nuclear, and hydroelectric technologies. However, as noted in Section 1.3.3, the eligibility of these technologies to contribute to compliance with the 100% target varies across scenarios.

The “renewable combustion turbine” technology is specified as “renewable” instead of identifying a specific fuel type because this type of technology could use a variety of types of purchased renewable fuels, including but not limited to biodiesel, biogas, ethanol, synthetic natural gas, and hydrogen. However, given that robust markets (and supply infrastructure) for hydrogen and synthetic methane do not currently exist, we assume that any RE-CTs operating between 2021 and 2044 is fueled with a biofuel (liquid fuel) or biogas. But, by 2045, we assume that development of robust markets for hydrogen or synthetic methane develop, and therefore that these CTs are converted to 100% (market purchased) hydrogen fuels. Given that the Early & No Biofuels scenario does not allow the use of biofuels or biogas, RE-CTs are not allowed to be built until 2045, at which point they are assumed to be fueled by hydrogen.

The two hydrogen technologies, H_2-CTs and hydrogen fuel cells, in contrast to the RE-CT technology, are assumed to self-produce hydrogen fuel, and therefore serve as long duration storage technologies. Both technologies use zero- or low-variable cost generation to produce hydrogen which is subsequently converted to and stored as ammonia. The ammonia is then assumed to be stored locally (in tanks) until generation from these resources is required, at which point it is cracked to create hydrogen, which is subsequently used in a CT or fuel cell. With exception of the planned phase-in of hydrogen fuel at IPP, new H_2-CTs and fuel cells are not allowed to be built in LA100 scenarios prior to 2030.

To meet the electricity demand needs for hydrogen production, we allow some market purchases of electricity to supplement LADWP generation (described in Section 2.4.2). This is the sole exception to our requirement that LADWP be completely independent for reliability purchases. However, these purchases are during off-peak periods well in advance of peak demand periods, and therefore do not represent a significant impact on potential resource adequacy.

2.4.1 Capacity

Wind, solar, and diurnal storage resources (battery and pumped hydro) play a substantial role in meeting peaking capacity requirements, accounting for approximately half (or more) of the total planning capacity[25] in 2045 across all scenarios (see Figure 28).

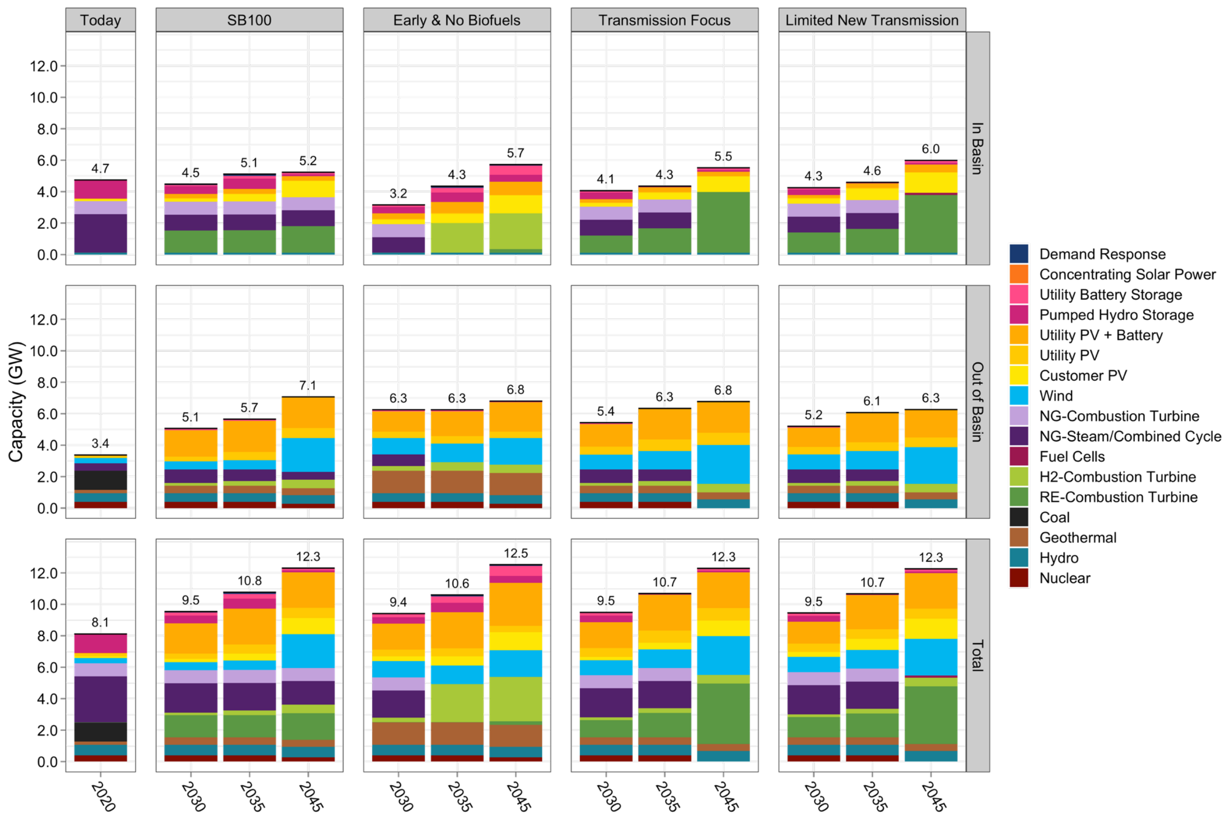

Figure 28. The evolution of total firm capacity (the amount of capacity associated with a generation asset that is reliably available during times of system stress) by location for the LA100 High load scenarios

In-basin capacity is shown on the top row, out-of-basin capacity is shown in the middle row, and total firm capacity is shown in the bottom row.

However, there are days to weeks when the availability of wind and solar resources is so low that insufficient energy exists to meet load during all times of the day, even given the extensive ability to diurnally shift energy. Certainly, more wind and solar capacity could be built to create additional available energy, however, the incremental capacity credit of these resources, even with additional diurnal storage, is very low as the LADWP system approaches 100% renewables. Furthermore, these additions would result in increases in energy availability not just on days with a 24-hour renewable energy deficit, but also increases in surplus energy during high-resource-quality periods when wind and solar availability already exceeds 24-hour load. On balance, this

[25] A planning reserve margin is often used in power system planning to ensure the resource adequacy—the ability of the system to meet load during times of system stress—of the system is sufficient. It is defined as a percentage of capacity resources above a reference, typically projected peak demand. The total planning capacity target is the refence level plus the reserve margin. A 15% planning reserve margin and a peak of 10 GW would imply a total planning capacity requirement of 11.5 GW.

means that the value of additional wind or solar capacity is declining as they would be producing a decreasing amount of usable energy[26] and contributing less to meeting peak load conditions. As a result, other options for maintaining energy balance during these periods can be procured at lower net-system cost.

So, in order to cost-effectively balance supply and demand on every day of the year, renewable firm capacity resources—resources that can generate on demand and provide uninterrupted supply over the course of days to weeks—are deployed across the LA100 scenarios. Historically, these services have been provided by in-basin natural gas generation units at the Harbor, Haynes, Scattergood, and Valley generation sites. However, a number of these units are once-through cooled and expected to retire by 2030.

Figure 29 shows the nominal capacity of just the firm capacity resources for each scenario, by location (in vs. out of basin). In the SB100, Transmission Focus, and Limited New Transmission scenarios, as OTC power plants are retired and load grows, new in-basin renewably fueled combustion turbines are deployed to meet the firm capacity deficit by 2035. Outside of the basin, in the same timeframe, the replacement of IPP coal units with units burning natural gas and hydrogen makes up for a portion of the retired coal capacity, while a small amount of geothermal capacity provides additional firm capacity. Wind, solar, and diurnal storage assets continue to make up a substantial portion of the firm capacity needs, but as noted above, their declining capacity credit make it cost-prohibitive to meet all capacity needs with those assets alone. Firm capacity technologies thus make up the difference.

[26] If, however, new or existing industries identify beneficial uses for the very low-cost surplus energy, the value of this surplus energy could substantially increase, thereby changing the competitiveness of wind and solar vs other firm capacity assets.

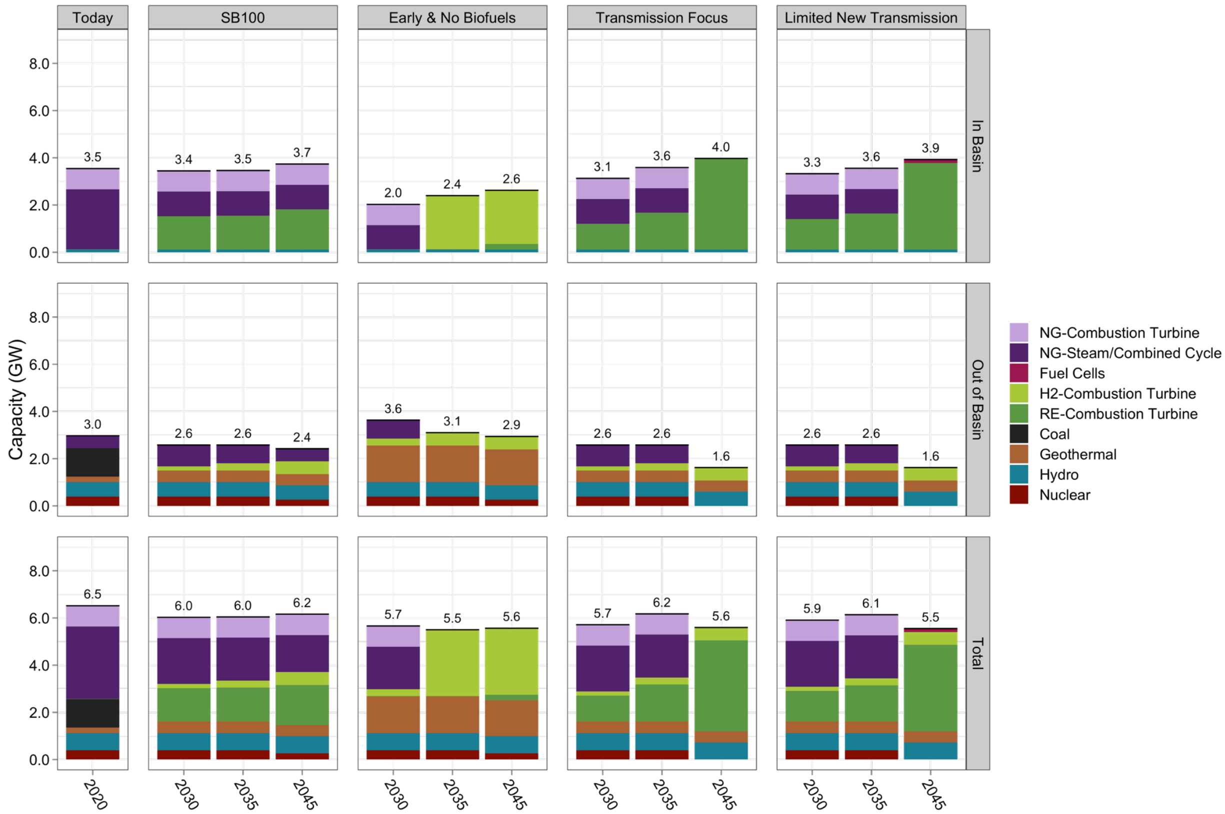

Figure 29. Nominal capacity of firm capacity resources, High scenarios, 2030–2045

In the 2045 timeframe, the SB100, Transmission Focus, and Limited New Transmission scenarios diverge. In the SB100 scenario, total firm capacity grows over the analysis period with the increase in peak load conditions, but the mix of firm capacity resources remains relatively constant. Natural-gas units can continue to be used for energy and capacity services while being offset by renewable energy credits, and new renewably fueled CTs meet the growing need for capacity.

However, under the Transmission Focus and Limited New Transmission scenarios, all natural-gas units must be retired by 2045. As a result, we observe a large shift in the firm capacity mix from 2040 to 2045—the remaining in-basin natural-gas units retire and are compensated for by substantial additions of new renewably fueled CT capacity both in and out of the basin.

Under the Early & No Biofuels scenario, renewably fueled CTs (which assume a market-supplied fuel) are not permitted until 2045, given the assumption that market-supplied hydrogen is not available until the 2040s. Therefore, new in-basin firm capacity resources are limited to higher-cost hydrogen technologies (H_2-CTs and fuel cells) in the 2030–2040 timeframe. In this scenario, associated with the retirement of the OTC units are additions of approximately 1.2 GW of geothermal capacity (excluding the capacity at IPP) in 2030 followed by approximately 2.5 GW of H_2-CT capacity in 2035, the large majority of which is in the LA Basin. This reliance on H_2-CT capacity as primary source of firm capacity persists in the Early & No Biofuels scenario through 2045.

Table 5 summarizes the 2045 capacity of in-basin dispatchable capacity by scenario, along with 2020 for comparison.

Table 5. Summary of In-Basin Dispatchable Capacity (GW) by Scenario (2045)

	Capacity (GW)				
Scenario	**Natural Gas**	**RE-CT**	**H_2-CT**	**H_2-Fuel Cell**	**Total**
2020	3.9				3.9
Ltd. Trans. – High		3.7		0.1	3.8
Ltd. Trans. – Moderate		4.2		0.1	4.3
Early/NoBio – High		0.2	2.3		2.5
Early/NoBio – Moderate		0.9	2.5		3.4
SB100 – High	1.9	1.7			3.6
SB100 – Moderate	1.9	2.5			4.4
SB100 – Stress	1.9	3.6			5.5
Trans. Focus – High		3.9			3.9
Trans. Focus – Moderate		4.4			4.3

2.4.2 Generation

Although firm capacity resources are deployed across all LA100 scenarios at the gigawatt scale, this type of resource, with exception of geothermal capacity, is relied on infrequently to provide energy and is typically only dispatched under times of stress or low wind and solar output.

Renewably fueled CTs (H_2-, biofuel-, or biogas-CTs) and fuel cell technologies all represent very high-variable-cost technologies due to the high cost of producing the fuels.[27] As a result, it is cost optimal to keep their dispatch to a minimum. Geothermal, on the other hand, is a high-capital-cost, low-variable-cost technology and is therefore used more consistently, although it is allowed to vary output as needed. For the scenarios that allow natural gas through 2040 (all but Early & No Biofuels), generation from the renewable fuel technologies (RE-CTs, H_2-CTs, and fuel cells) is used to meet less than one half of one percent of total energy through 2040. But in 2045, after the natural gas plants have all retired in the Early & No Biofuels, Transmission Focus, and Limited New Transmission scenarios, these technologies deliver between 4% and 9% of total energy needs. The SB100 scenario, which maintains natural gas capacity through 2045, continues to have very low contributions from RE-CTs, which generates between 0.1% and 0.5% of energy needs from renewably fueled technologies.

[27] In the case of hydrogen technologies, because the fuel is assumed to be self-produced by LADWP, the actual variable cost of generation is almost entirely the variable O&M costs (excluding fuel) of the H_2-CT. The costs associated with hydrogen fuel production are instead reflected in the upfront capital costs of the fuel production infrastructure, and the capital costs of the wind, solar, and geothermal capacity used to generate electricity for the fuel production. However, because there are increased fixed costs depending on the amount of energy generated by the H_2-CTs, it is advantageous to minimize their utilization, much like RE-CTs. As such, they can be interpreted as a high-variable-cost technology.

Geothermal capacity, on the other hand, has a much more consistent but small contribution to energy needs over time. Across the scenarios most of the geothermal capacity is deployed by 2030, when it makes up roughly 10%–11% of generation in the SB100, Transmission Focus, and Limited New Transmission scenarios, and approximately 18% in Early & No Biofuels. In 2045 the geothermal share of generation drops to 6%–8% in the SB100, Transmission Focus, and Limited New Transmission scenarios as generation from other technologies increase. But, under the Early & No Biofuels scenario, the share of geothermal increases slightly—to 23% of total energy needs in the Moderate scenario and 19% in the High scenario.

Generation from these firm capacity assets plays a critical role during periods of low wind and solar availability. Figure 30 illustrates how supply-demand balance is maintained even on days with lower than usual solar and/or wind availability in the Early & No Biofuels – High scenario. November 15 is a low wind day, and November 16 is a particularly low solar day. Extended-duration storage (with many days of capacity) in the form of H_2-CTs are dispatched because short-duration storage resources such as batteries were depleted in the prior day and their storage reservoirs are not able to be sufficiently recharged over the next 24-hour period. H_2-CTs can use previously curtailed energy from other times of the year to create hydrogen that is deployed during these times of need. In the case of the Early & No Biofuels – High scenario, curtailed energy in 2045 does not provide enough generation to produce the full amount of electricity needed for electrolysis. A shortfall of 7.5 TWh (inclusive of inefficiencies of electricity-H_2-ammonia-H_2 fuel conversion) is observed with the existing build-out. We assume this electricity can be purchased off-peak well in advance of when it is needed and/or self-produced fuel is supplemented with purchased fuel.

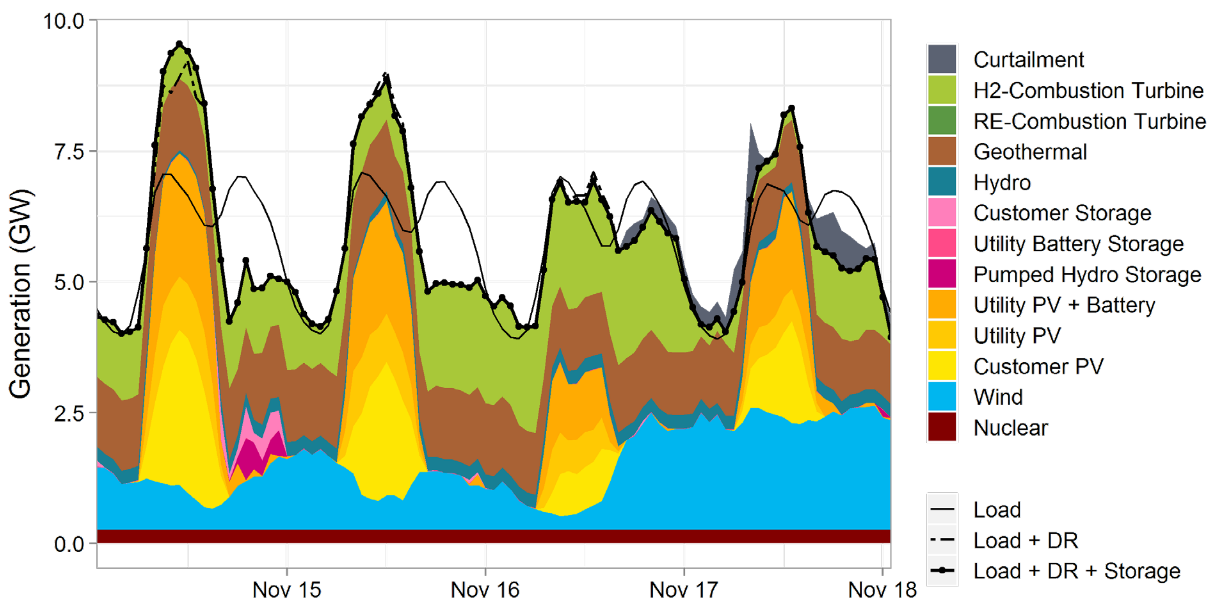

Figure 30. Hourly dispatch for four low wind and solar days of 2045 in the Early & No Biofuels – High scenario

2.4.3 Seasonal Storage Infrastructure—Hydrogen and Renewable-Fuel Alternatives

All LA100 scenarios rely on CTs to provide in-basin dispatchable generation to meet peak demand and to address transmission outages. The infrastructure requirements for these scenarios vary substantially depending on fuel source in each scenario. The SB100 scenario allows for continued use of some natural gas, supplemented by renewably fueled CTs. Natural gas is currently delivered to the in-basin generators via the existing pipeline network. The gas is combusted to either heat air (combustion turbine) or create steam (steam turbine), the heat of which in turn drives the turbine to produce electricity. Natural-gas combined-cycle uses both these processes to improve the energy efficiency of the plant. Combustion turbines, with lower efficiencies and also lower capital costs, can be operated more flexibly (e.g., start more quickly and potentially faster changes in output) compared to combined-cycle plants, and have traditionally been used as peaker plants to meet the extreme periods of demand. Combined-cycle plants with higher efficiencies, and therefore lower operating costs, are operated more continually in today's LADWP system, and also as allowed in the SB100 scenario.

There are several pathways for renewably derived fuels, depending on the scenario. Figure 31 shows multiple pathways for conversion of renewable resources into electricity via the production of storable liquid, solid, and gas fuels.

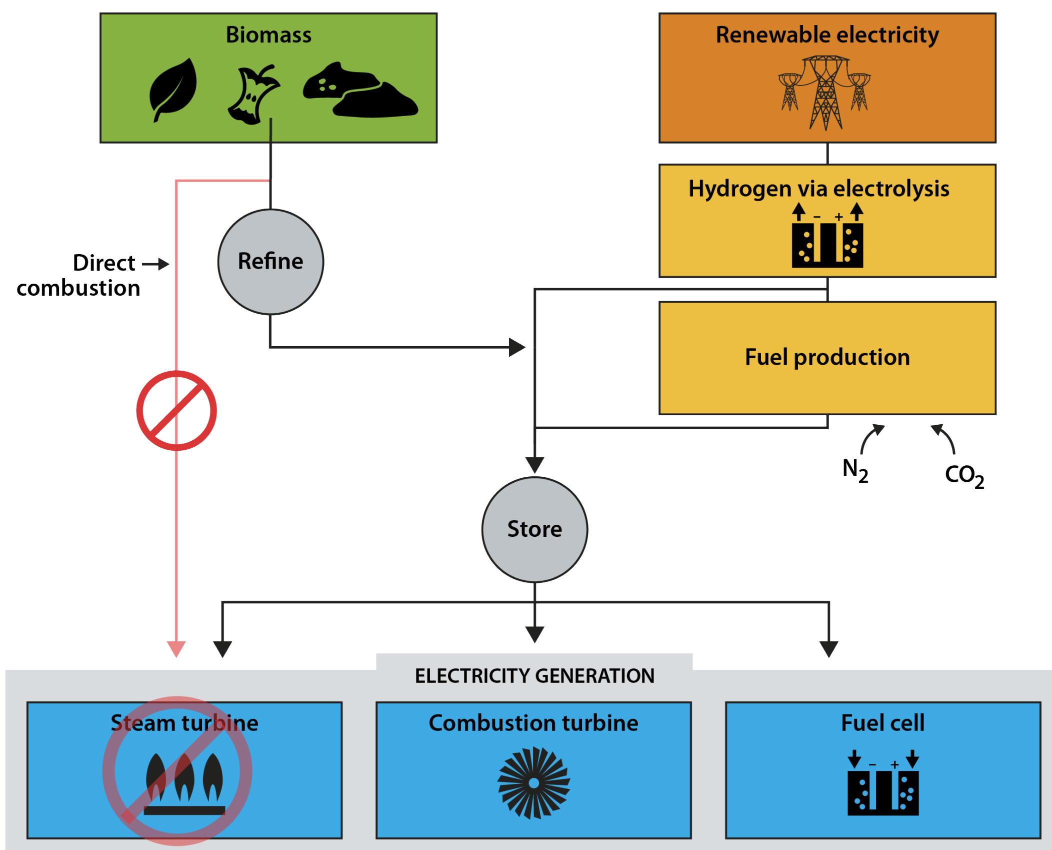

Figure 31. Sources and pathways to convert biomass and renewably derived electricity to storable fuels and then to generate electricity

- **Solid Biomass (direct combustion):** Solid biomass (such as forest waste) or organic trash (such as paper) can be burned directly to produce steam and turn a turbine in a generation process similar to burning fossil fuels. The LA100 study prohibits technologies that burn solid biomass directly due to associated air pollution. Biogas is allowed in many scenarios and is described separately, below.
- **Biofuel Combustion:** Biomass including certain crops or animal waste can be converted into a clean-burning fuel through two main pathways. The first is via biofuel refining, which can produce products such as ethanol or biodiesel. The second is biogas, typically produced by anaerobic decomposition of municipal solid waste in landfills or from livestock manure. Biogas is primarily methane (natural gas). Both biofuels and biogas can then be combusted in a combustion turbine, similar to natural gas. While this process releases carbon dioxide (CO_2), and some small amounts of NOx, the process is considered CO_2 neutral, as the original biomass was produced by capturing CO_2 from the atmosphere via photosynthesis.
- **Renewable Electricity-Derived Fuel Combustion**: Renewable electricity sources (e.g., wind, solar) can be used to produce various fuels for storage, to be used for electricity generation at a later date. The first step is electrolysis, which turns water into hydrogen and oxygen. This hydrogen gas may then be stored and used in a combustion turbine to make electricity. Alternatively, hydrogen can be converted into a fuel that is easier to store and transport, such as natural gas (methane) or ammonia. The combustion process can produce small amounts of NOx.
- **Fuel Cells (using renewable fuels)**: Fuel cells use chemical energy of a fuel to produce electricity (similar to a battery). Fuel cells may use a number of renewable-electricity derived fuels (e.g., hydrogen) or may use a limited number of biofuels. Fuel cells produce no NOx and very little noise. However, they are currently higher cost than combustion options, and only deployed in limited quantities in the Limited New Transmission scenario.

Alternative-fuel combustion turbines are at various stages of maturity. Biogas is primarily methane, the primary constituent of natural gas, so can be burned with little to no modifications of existing combustion turbines. It can also be injected into the existing natural gas pipeline network if sufficiently processed to remove contaminants. As a result, it can potentially be used "virtually" via remote purchases and delivery to account for the fuel burned at the power plant. The primary challenge of biogas is fuel availability and ensuring it is produced with the necessary quality to be permitted into the natural gas system.

Other forms of biofuels such as biodiesel can also be burned in CTs with fairly minimal modifications. An alternative to CTs is reciprocating engine plants, with similar efficiencies and costs, so could be a functional alternative to combustion turbines depending on fuel type. Liquid biofuels would likely require delivery and on-site storage, as opposed to the "just in time" nature of the pipeline network.

The greatest challenge is associated with hydrogen or hydrogen-derived fuels. This technology is the least mature, although turbines that can burn natural gas/hydrogen blends are available. Hydrogen can be generated via electrolysis and stored in underground formations located outside of the LA Basin. This allows for seasonal storage. Delivery of hydrogen gas into the basin requires new pipeline networks. Alternatively, storage of hydrogen in the basin likely requires conversion to another form. We assume in-basin storage in the form of ammonia, which can then be converted back into hydrogen, or used with ammonia/hydrogen blends.

The introduction of hydrogen-fueled generation represents a new technology for LADWP, and hence new requirements for siting associated infrastructure. The footprint for the CTs themselves are the same as current natural-gas-fueled technology. For H_2-CTs there are additional requirements for hydrogen production, conversion into a storable fuel (we assume ammonia), and storage. This section reviews example site requirements using the Early & No Biofuels – Moderate scenario, which is the scenario with the highest hydrogen-related capacity and therefore the most challenging in terms of associated infrastructure. The total installed capacity is listed in Table 6. All hydrogen is assumed to be produced by LADWP before 2045, when we assume a renewable-hydrogen market has developed sufficiently to allow for market purchases. hydrogen-fueled capacity represents on-site production. Renewably fueled capacity represents market-purchased hydrogen, which is assumed not available until 2045.

Table 6. Total Cumulative Capacity by Year of Hydrogen-Fueled CTs in the Early & No Biofuels – Moderate Scenario

Location	Hydrogen Fuel Origin	Total Capacity (MW)				
		2025	2030	2035	2040	2045
In-basin	LADWP-Produced	0	0	2,100	2,500	2500
Out-of-basin	LADWP-Produced	60	300	550	550	550
In-basin	Market Purchase	0	0	0	0	850

Capacity by location is provided in Table 7. Note, after analyzing RPM results with additional power flow analysis, we found value in moving 500 GW of H_2-CT capacity from Valley to Scattergood. The results in this section reflect this update, which was made after the final PLEXOS analyses.

Table 7. New Hydrogen-Related Capacity by Location in the Early & No Biofuels – Moderate Scenario in 2045

Location	MW of Capacity (2045)			
	H_2-Fueled	RE-Fueled	Total	2020 Natural Gas Capacity for Comparison
IPP	540	0	540	NA
Harbor	550	350	900	550
Haynes	830	0	830	1,740
Valley	400	500	900	690
Scattergood	750	0	750	880
Total In-Basin	2,500	850	3,400	3,850
Total	**3,060**	**850**	**3,900**	**3,850**

Overall, about 3.1 GW of in-basin hydrogen-fueled and renewably fueled CT capacity is constructed by 2045, compared to 3.9 GW of existing in-basin natural gas-fueled capacity in 2020. Some of LADWP's existing combustion turbines could potentially be retrofitted to accommodate renewable fuels. Note that while we show we can maintain steady-state balance with this in-basin capacity, additional power flow analysis could suggest further redistribution of in-basin capacity as discussed in Section 4.2.

For the CTs to provide firm capacity, the hydrogen-based fuel must be stored or readily procured. We do not anticipate in-basin storage of large volumes of gaseous or liquid (cryogenically stored) hydrogen. The large volumes of hydrogen needed will largely be stored outside the basin in geologic formations and delivered to the site in gas form via modified pipeline, or in the form of ammonia. Some on-site storage of hydrogen in the form of ammonia is likely desirable to ensure reliable operation. Storage energy density of ammonia and two renewable fuels as comparison is listed in Table 8.

Table 8. Fuel Energy Density by Type

Fuel Type		Fuel Energy Density (MJ/liter) (Higher Heating Value)	Net Fuel Energy Density (kWh/gallon) assuming a 9,000 BTU/kWh heat rate
Renewable Fuels	Ethanol	24	9.6
	Biodiesel	36	14.4
Hydrogen Stored as Ammonia		11.5	4.6

Note that conventional diesel fuel has about the same energy density as biodiesel.

If it were desirable to have three days of stored fuel for all generators operating at 100% output, Table 9 provides the storage capacity requirements of ammonia.

Table 9. Storage Requirements for the In-Basin Hydrogen-Fueled CTs in Early & No Biofuels – Moderate Scenario in 2045

Location	Hydrogen Requirements (as Ammonia)		
	Capacity (MW)	GWh for Three Days of Generation	Fuel Volume Required (Million Gallons)
Harbor	900	70	14
Haynes	830	60	13
Valley	890	60	14
Scattergood	750	50	12
Total In-Basin	**3,470**	**240**	**53**

Alternatively, hydrogen could potentially be augmented by renewably derived hydrocarbons (or even fossil fuels) for emergency purposes, depending on regulatory considerations. If liquid hydrocarbons were allowed as an emergency fuel, the storage requirements for the H_2-CTs would be reduced by more than half (Table 10).

Table 10. Storage Requirements for the In-Basin RE-Fueled CTs in Early & No Biofuels – Moderate Scenario in 2045 if Allowed to Use Liquid Hydrocarbons for Emergency Purposes

Location	RE-Fuel Volume Required (As Biodiesel) (Million Gallons)
Harbor	5.4
Haynes	5.0
Valley	5.4
Scattergood	4.4
Total In-Basin	**20.3**

For context, a list of sites identified for possible repurpose as fuel storage or other infrastructure is listed in Table 11.

Table 11. Storage Tank Sites That Can Potentially Be Repurposed for Fuel Storage

Site	Number of Tanks	Diameter (Meters)	Notes
Harbor	3	30.5	Southeast corner of site
Haynes	2	16.5	Near units 11–16
Haynes	2	12.5	Near units 11–16
Haynes	1	6.5	Near units 11–16
Haynes	1	15	Between units 4 and 5
Haynes	1	8.5	Between units 4 and 5
Haynes	1	16	Near units 1 and 2
Haynes	1	20	Near units 1 and 2
Haynes	1	60	Tank "E"
Haynes	4	50.8	Tank "D" + 3 storage tanks south
Scattergood	2	14	Southwest corner of site
Scattergood	2	24	East side of site
Scattergood	1	28.5	East side of site
Valley	1	25.5	Southeast of CT
Valley	1	29	North of CT
Valley	1	51.5	North of CT

2.5 Looking Deeper: The Role of Transmission

All scenarios rely heavily on the use of the transmission network to access high-quality renewable resources while remaining robust to extended transmission outages. Even the Limited New Transmission scenario heavily utilizes the existing transmission infrastructure without making any additional upgrades beyond current plans. Additionally, transmission plays a key role in meeting all resource adequacy needs and ensuring there is sufficient capacity to meet load even when key lines may have an outage.

2.5.1 New Capacity (Upgrades)

Transmission upgrades are an important aspect of all core scenarios. All scenarios include all firm transmission projects planned by LADWP as of June 2020, and all scenarios aside from the Limited New Transmission scenarios can upgrade any existing transmission line or transformer[28] to which LADWP owns or holds rights to some portion. The Transmission Focus scenario also includes the construction of a new DC transmission pathway into the basin coupled with in-basin DC ties to key transmission sites to create additional transmission to access remote resources.[29] All eligible scenarios require in-basin upgrades by 2045, with the largest upgrades occurring in the SB100 – Stress scenario. Table 12 summarizes new transmission capacity for each scenario that allows upgrades beyond what are in existing plans.

Table 12. Transmission Infrastructure Upgrades and New Builds by Each Scenario Allowing New Transmission Upgrades and Builds

Location	SB100			Early & No Biofuels		Transmission Focus	
	Mod.	High	Stress	Mod.	High	Mod.	High
In-Basin AC	54 MW 1 line[30] ~3 km	232 MW 1 line ~3 km	634 MW 5 lines ~50 km	231 MW 3 lines ~30 km	468 MW 3 lines ~30 km	57 MW 1 line 3 km	127 MW 1 line 3 km
In-Basin DC	0 MW	0 MW	0 MW	0 MW	0 MW	7500 MW 3 lines 60 km	7500 MW 3 lines 60 km
Out-of-Basin	0 MW	0 MW	174 MW 1 line 57 km	2455 MW 3 lines 379 km	2354 MW 3 lines 379 km	0 MW	0 MW
Out-to-In-Basin	0 MW	0 MW	0 MW	0 MW	0 MW	1700 MW 1 line 110 km	1700 MW 1 line 110 km

[28] Transformers are represented indirectly in RPM by derating lines wherever transformer ratings are less than the ratings of the conductors they connect to. Therefore, there is no cost differentiation between line upgrades and transformer upgrades.
[29] This DC transmission backbone is exogenous to the model—i.e., it is not a decision made by the model but rather it is assumed that this backbone is built. Although the investment in the DC backbone is not an investment identified by the optimization algorithm the costs of the transmission are reflected in total costs metrics.
[30] As explained in a footnote above, each "line" described in this table entails either a reconductored circuit or an upgraded transformer.

While the SB100 and Transmission Focus – Moderate scenarios include only minor AC upgrades for one line within the basin (in addition to the new DC lines in the Transmission Focus scenario), all other scenarios substantially upgrade the thermal capacity of at least one line, with the SB100 – Stress scenario upgrading five lines for a total of 634 MW. Out-of-basin transmission upgrades only occur in the scenarios with the highest load growth (SB100 – Stress) and when in-basin biofuels are not allowed (Early & No Biofuels scenarios). In particular, the Early & No Biofuels scenarios both upgrade more than 2 GW of out-of-basin transmission capacity in order to provide further access to out-of-basin geothermal, wind, and solar resources.

While these out-of-basin upgrades may include purchasing transmission rights or physically upgrading the lines, the new in-basin capacity represents potentially significant new infrastructure. Additionally, the Transmission Focus scenario includes building three new DC transmission lines of 2.5 GW within the basin in addition to conversion of the Victorville to Century AC line to a 2.5 GW DC system (which represents approximately a 1.7 GW increase in the thermal capacity rating of the line). DC transmission provides several advantages, primarily the ability to control the flow of power, and can increase the effective utilization of the transmission network. Power flow on conventional AC transmission circuits can be controlled only indirectly by adjustment of loads and generation proximate to the circuits' terminations. The flow of power on each line influences flows on all other lines, so one fully loaded circuit can limit power flow across the entire network, constraining the whole system's ability to serve load. Power flow on DC transmission circuits, on the other hand, can be controlled simply by adjusting the control systems that reside in the converter stations that terminate the DC circuits and convert the DC power to AC to interface with the existing AC transmission network. Essentially, the power flow on DC transmission can be "dialed in" to a specific level within a very wide range. If the DC terminals are judiciously chosen, power can be injected into the AC network from the DC system and this power injection can mimic the beneficial aspects of existing conventional generation on the AC network. The DC backbone can then replace conventional generation at local generating stations, and significantly reduce the number of AC transmission upgrades that would otherwise be required to maintain current transmission reliability.

The maps in Figure 32 show the approximate location and extent of the transmission upgrades and new builds by 2045 for all scenarios. Transmission line locations are stylized here, and purely show the straight-line connections between nodes. The DC upgrades would connect Victorville with Century on the existing Victorville–Century path before proceeding to Harbor via the Los Angeles River and onward as an underwater cable to link to Haynes and Scattergood. As discussed above, this allows for higher utilization of out-of-basin solar and geothermal resources and increased injection of power into the 138-kV portion of the LADWP system's transmission network from its periphery. The most substantial in-basin upgrades of the existing AC network are made in the SB100 – Stress Load scenario, where upgrades chiefly facilitate the transfer of out-of-basin renewable power south from where much of it enters the basin at the northern reaches of the 230-kV network. Upgrades strengthening the lines nearest LADWP generating sites Valley and Scattergood are common among the scenarios, allowing for the integration of various new resources at those sites, including battery storage, RE-CTs, H_2-CTs, and utility-scale PV.

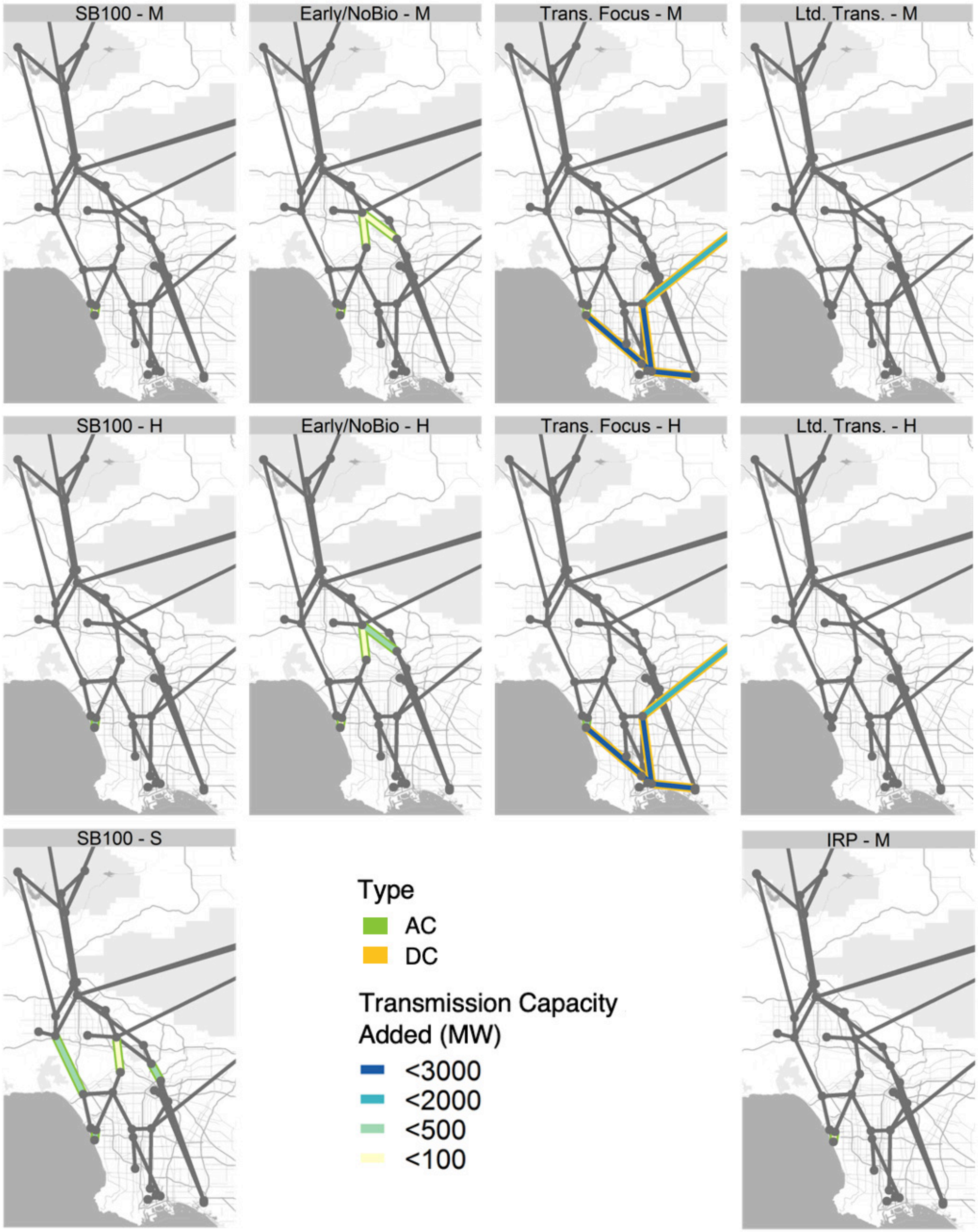

Figure 32. Capacity and current type (AC vs. DC) of in-basin and into-basin transmission upgrades added by 2045 for all scenarios

As above, these upgrades are additional to all firm projects as of June 2020 as communicated by LADWP. The Limited New Transmission scenario does not allow transmission upgrades but is included for completeness. Note that the IRP scenario does not go beyond 2035.

The upgrades discussed here do not include additional upgrades that may be necessary as revealed by the contingency analysis discussed in Section 4.2.3. The analysis identified a number of upgrades that may be needed if there were a large failure of the transmission network to avoid overloads. Because the contingency analysis was performed for only the most difficult scenarios (Early & No Biofuels), we cannot perform a comparison among the scenarios, and a site-by-site cost estimate is needed for each of the specific upgrades, including a comparison to alternatives. In addition, there may lower-cost alternatives, such as shifting capacity within the basin, and increased use of flexible AC transmission and more dynamic operation in response to contingency events. These options are discussed in more detail in Section 4.2.3.

2.5.2 Operations

Consistent with current LADWP operations, out-of-basin generation continues to make up the majority of total energy needs to meet load. As a result, the out-to-in-basin transmission assets are heavily relied on across all scenarios to bring renewable resources into the basin and the in-basin assets are relied on to move that energy from the three main points of delivery to all areas of throughout the city of Los Angeles. Although the reliance on out-to-in-basin transmission does not represent a fundamental change in typical operating conditions of the LADWP system, given that the LA100 scenarios include load growth and, with exception to the Transmission Focus scenario, no new or upgrades to existing out-to-in-basin transmission resources are identified, the overall loading on the key out-to-in-basin lines grows substantially over the study period. It is helpful to think of there being effectively three pathways by which energy can be imported into the LA Basin, each of which will be analyzed here: the Victorville–LA path, which is responsible for importing most of LADWP's electricity and consists of several transmission lines entering the city at three points; the path north from Haskell Canyon to Barren Ridge, which connects to resources near the town of Mojave in the Owens Valley; and the Pacific DC Intertie, which connects resources in the Pacific Northwest to LADWP at Sylmar Converting Station.

For the LA100 High load electrification scenarios, Figure 33 shows the average daily loading by scenario, hour, year, and season on LADWP's most important group of out-to-in-basin lines: the Victorville–LA path. This group of transmission lines is made up of three physical corridors into the LA Basin—two connecting in the north/northeastern part of LA (at Rinaldi and Toluca) and another connecting closer to central LA (at Century). Looking across years demonstrates that as load and the renewable share of generation grows with time the loading on the Victorville–LA pathway also grows. This growth in loading occurs across all scenarios and seasons. While the amount of energy flowing on the path in the Transmission Focus scenario is similar to the other three scenarios, the introduction in 2030 of the 1,700-MW DC backbone means that the line loading (flow as a percentage of the total path rating) remains much lower from then onward.

Looking across hours shows that generally the loading is concentrated during the middle part of the day—the hours when solar generation is highest. During these hours, the transmission is being used to import energy to both satisfy coincident load and charge in-basin storage (both diurnal and long-duration). However, in the spring and summer, we see more consistent (and high) loading of the pathway throughout the day, particularly in the Early & No Biofuels and Limited New Transmission scenarios, indicating the importance of this pathway for importing energy from wind, geothermal, and storage assets in addition to the large amount of solar capacity sited outside of the LA Basin. In fact, the pattern reverses slightly in the Early & No

Biofuels scenario in later years throughout the spring and summer, with imports of energy along the path higher in the evening and morning hours than during the daytime. There are two complementary reasons for this. Because 100% renewable energy is reached in 2035 under the Early & No Biofuels scenario and no gas generation is allowed, the system increasingly relies on imports of energy each night. In the low-load spring months and into the early summer, in-basin solar generation and renewable generation on other into-basin paths reduces the need for daytime imports from Victorville–LA, freeing up renewable generation that can instead be dedicated to the production of hydrogen for use at IPP later in the year. By July and into August, a wind profile that tends toward nighttime generation helps increase imports into the basin during those hours, but the system has transitioned into a state where more energy is often needed overnight than can be provided with variable renewables, geothermal, and nuclear, so the H_2-CT at IPP is committed to make up the difference.

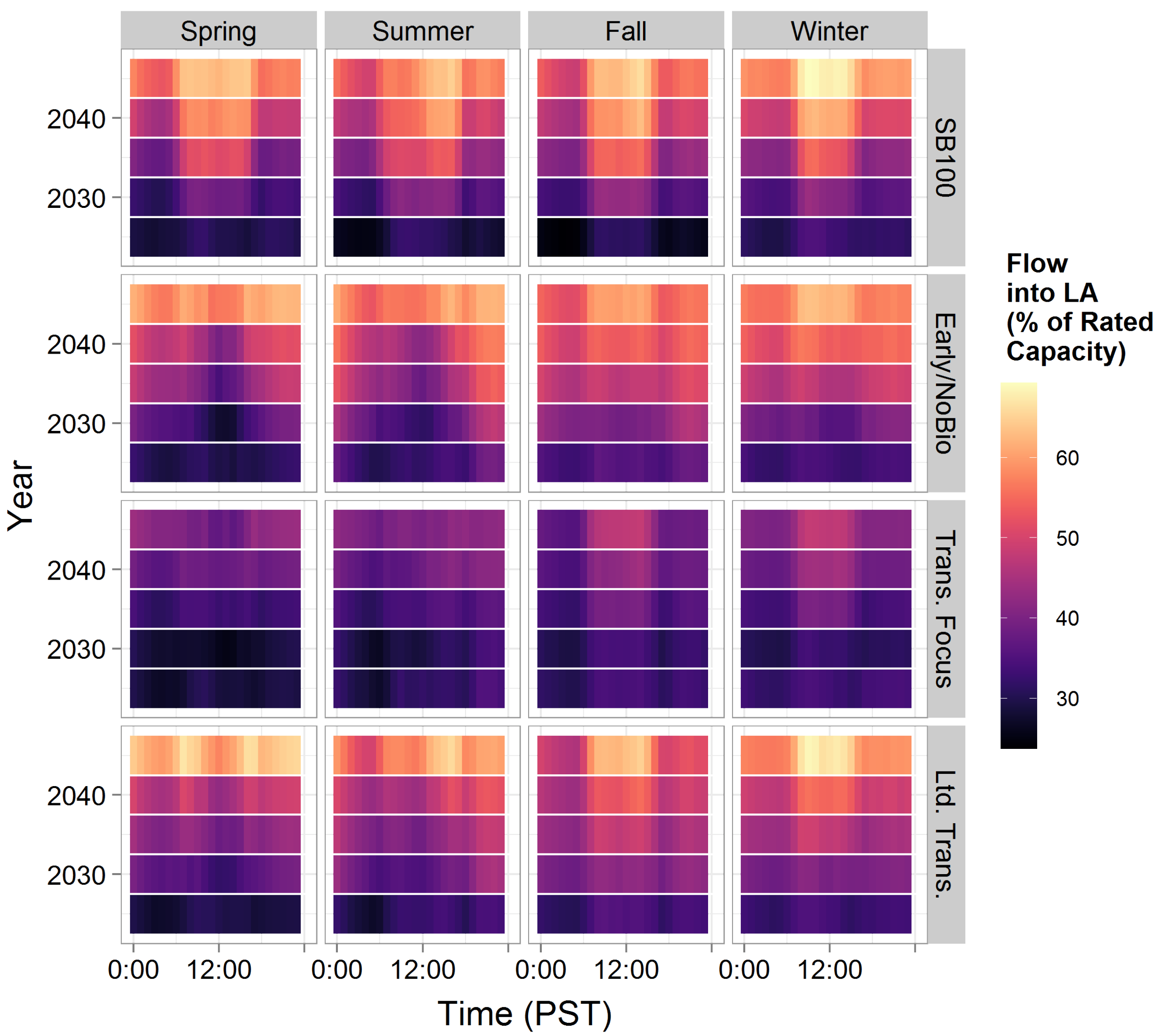

Figure 33. Average daily loading of the Adelanto–Rinaldi, Victorville–Rinaldi, Adelanto–Toluca, and Victorville–Century lines by season, hour, year, and scenario for the High scenarios

The operation of the path north from Haskell Canyon to Rosamond, Barren Ridge, Cottonwood, and the Owens Valley Electrical System presents a more distinct diurnal pattern than that of the Victorville–LA path. Figure 34 shows that without any geothermal or H_2-CT capacity installed on the path and little wind development relative to that of solar, imports closely follow daily solar profiles across scenarios and seasons and throughout the years studied. After sunset, the path often continues injecting some energy into the basin, albeit much less, with energy stored in utility PV+battery installations and a small amount of wind energy loading the path up to no more than 15% of its thermal rating. The Transmission Focus – High scenario builds more than 1 GW more PV on the path in 2045 than the other scenarios (to be discussed further below), leading to a much higher daytime utilization of this set of transmission lines.

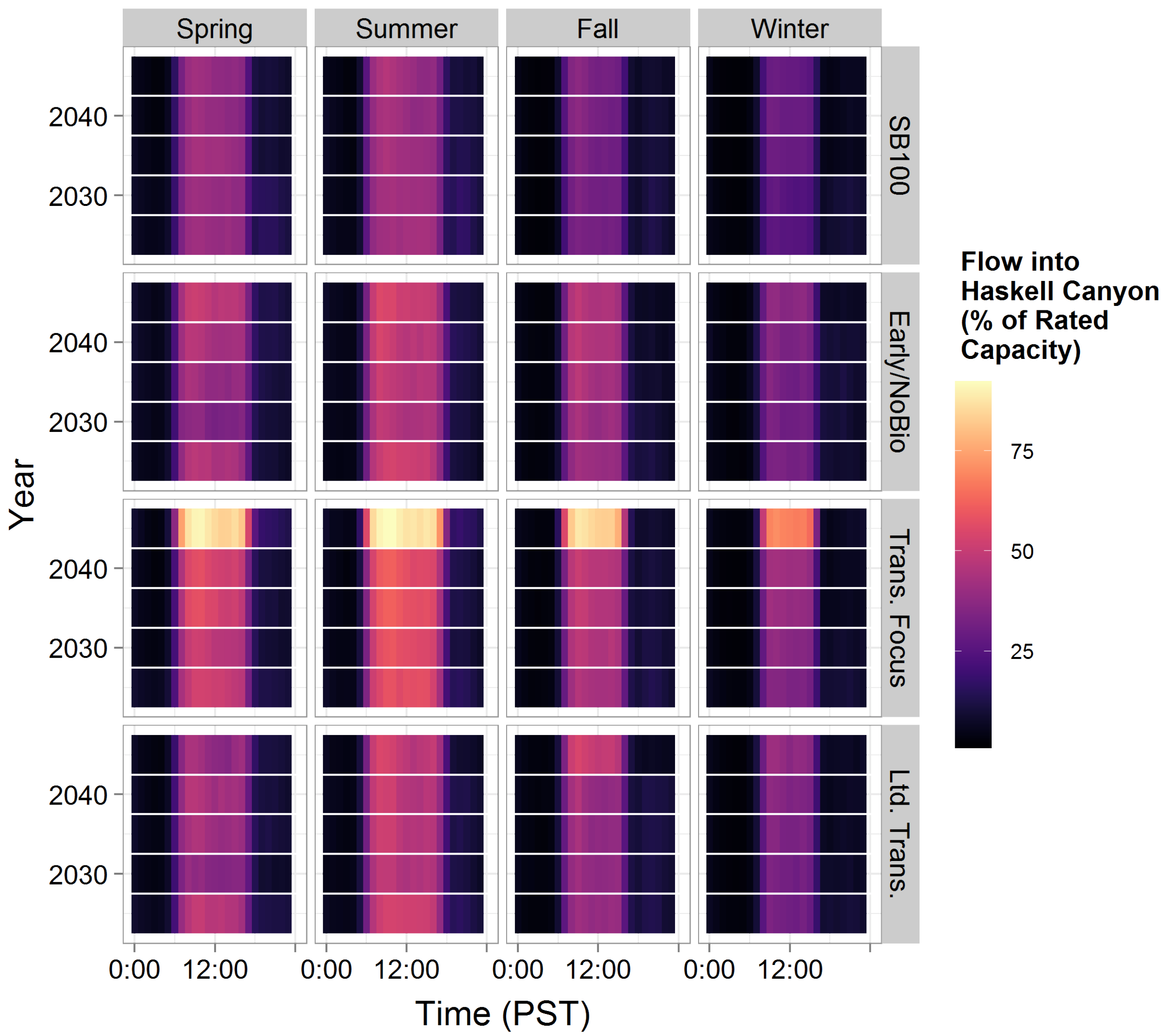

Figure 34. Average daily loading of the path north from Haskell Canyon to Rosamond, Barren Ridge, and the Owens Valley by season, hour, year, and scenario for the High scenarios

LADWP's share of the Pacific DC Intertie (PDCI) amounts to less capacity than the Victorville–LA path and the path north to Barren Ridge, but it can be expected to continue playing a role in bringing energy to the basin, nonetheless. Because LADWP must coordinate with the line's other owners to schedule its power flows, representing other BAs in the PCM is important in determining the line's operation. First, we can observe how LADWP would operate the line were it able to schedule its share of the path independently and only access the resources built on LADWP's behalf. Figure 35 shows the average daily operation of the PDCI as modeled in PLEXOS with the representation of LADWP as a physical island (as is the case with all other results in this section). Of particular interest in this plot is the heavy utilization of the PDCI shown in the Limited New Transmission scenario. Recall that this scenario does not allow any transmission upgrades or new builds beyond existing planned projects. This restriction on transmission results (for a variety of reasons) in more wind being accessed in the Pacific Northwest and imported into LA on the PDCI. As a result, the hourly average utilization of the PDCI in each season in this scenario follows the average wind profile. The fact that energy only ever flows from north to south across scenarios and years, however, is a reminder that representing load and generation centers in the Pacific Northwest is necessary to get a more complete picture of the path's operation.

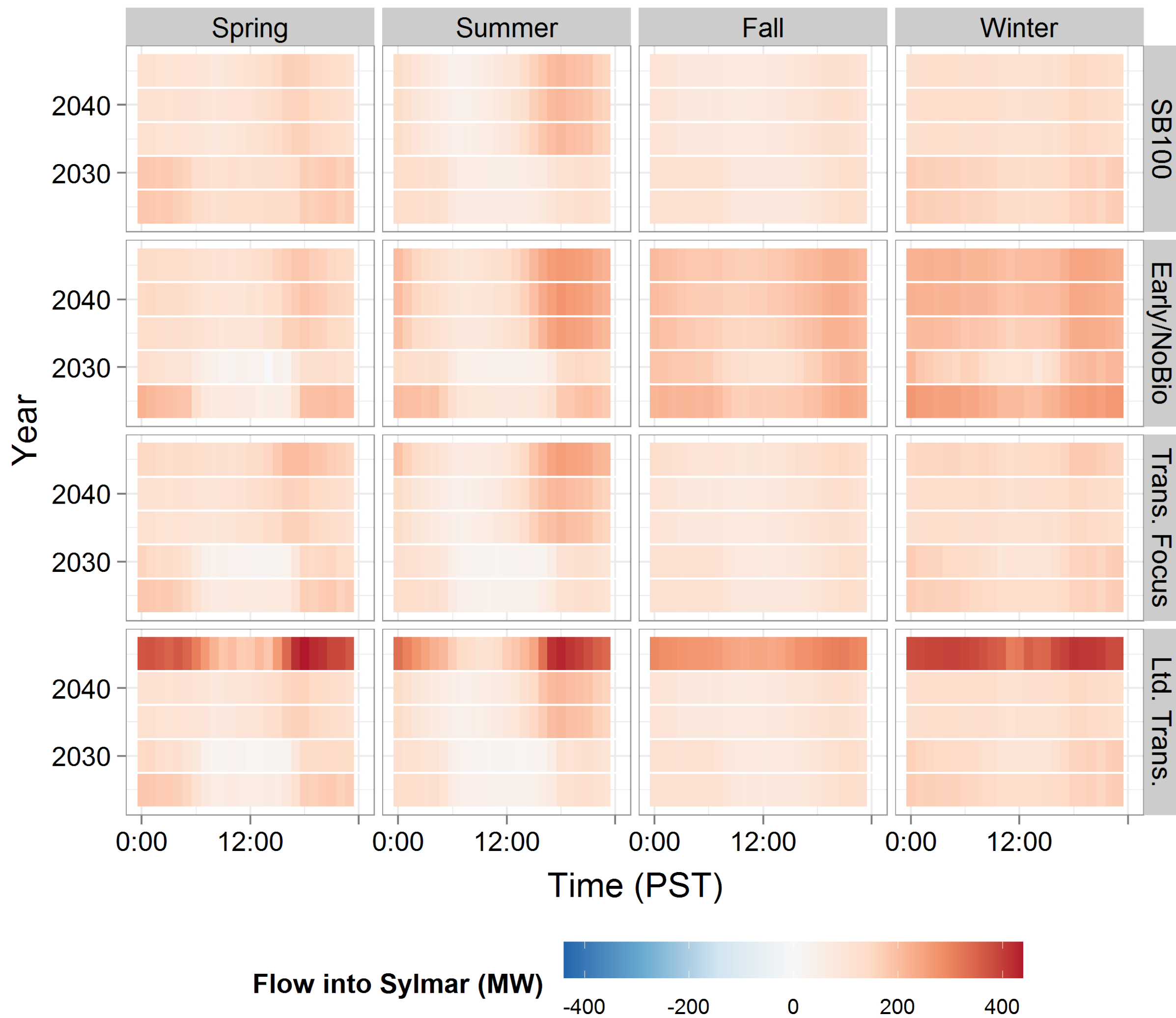

Figure 35. Average daily loading of the Pacific DC Intertie by season, hour, year, and scenario for the High (Islanded) scenarios

Modeling dispatch with a representation of LADWP as integrated with the rest of WECC helps to bookend what the operation of the PDCI might look like in coming years.[31] Figure 36 depicts operation of the PDCI in this WECC-integrated model configuration for the Early & No Biofuels – High scenario (with the line's entire capacity now represented, not just LADWP's share, as in Figure 35).[32] Negative flows indicate an export of power from LADWP and/or SCE to the north. As in the physically islanded representation, energy is sent southward in the nighttime hours, with most of this supply made up of wind energy generated in the Pacific Northwest. During the day, however, the PDCI is often utilized to send excess renewable energy generation (mainly solar) northward, especially in the springtime and winter, when the winter-peaking power system in the Pacific Northwest can take advantage of the excess supply due to the relatively low-load conditions present in Southern California. This seasonal arbitrage reflects the continued relevance of the original intent behind the PDCI's construction as the nation's first HVDC line in 1970. But the pattern of diurnal exchange superimposed on these seasonal energy transactions suggests a potential for more dynamic operation of the pathway as the renewable share of generation grows across the interconnection.

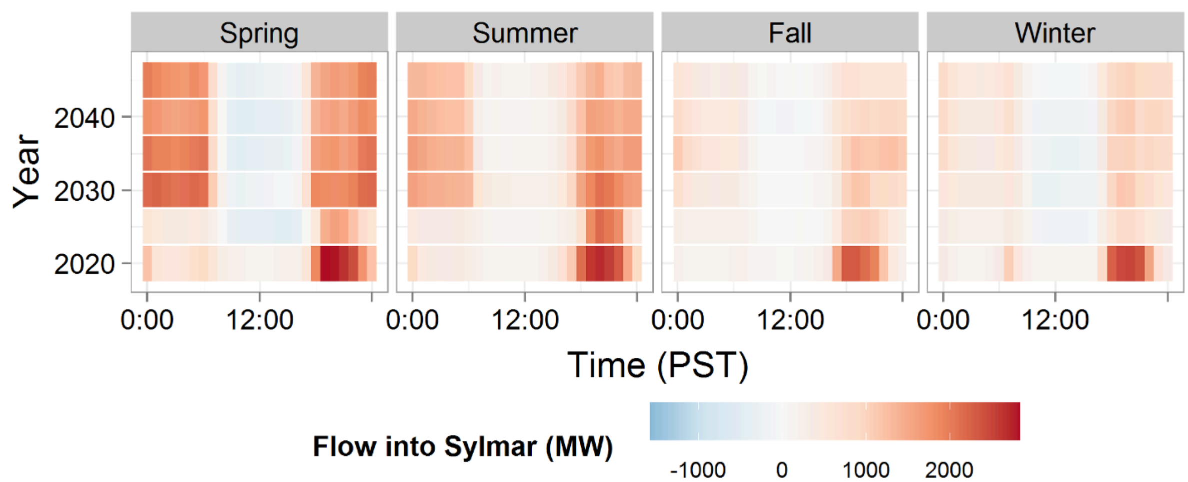

Figure 36. Average daily loading of the Pacific DC Intertie in a WECC-integrated model representation of the Early & No Biofuels – High scenario by season, hour, year

Figure 37 illustrates maps of transmission congestion in 2045, by scenario, of lines within and into the basin. Transmission congestion occurs when any circuit (that is, one set of conductors on a line, where some lines consist of several parallel circuits) is loaded at its maximum thermal capacity rating. Congestion does not indicate that load is not served but rather that the line cannot carry any additional energy for a prolonged period of time.

In general, the transmission network operates similarly across the SB100, Early & No Biofuels, and Limited New Transmission scenarios, with a somewhat different regime in the Transmission Focus scenarios due to the different topology introduced by the DC backbone.

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[31] For further discussion and comparison of annual generation between the "physical island" and "WECC-integrated" PCM configurations, see Section 3.7 and Figure 40.

[32] Because of decisions by the PDCI's stakeholders not represented in our modeling and the fact that barriers to trading energy are not represented here, the actual operation of the PDCI in 2020 may have differed substantially from the model results summarized here.

Within the LA Basin, we observe relatively consistent congestion on the main north-south pathways that connect the areas of the city broadly north and northwest of Highway 101 to all areas south and east of Highway 101 and Hollywood. This congestion is common across scenarios because the majority of out-to-in-basin transmission terminates in this northern part of the city and energy is frequently flowing from the north along these main transmission lines to distribute the out-of-basin renewable energy throughout the city. Interestingly, this congestion continues to be observed in the Transmission Focus scenario despite the conversion of the Victorville–Century line to DC, which substantially increases the capacity of the southernmost Victorville–LA corridor. The DC backbone terminates near the intersection of the 105 and the 110. The other unique aspect of the Transmission Focus scenario is that it alleviates all congestion on the northern Victorville–LA lines and instead we observe congestion along the DC backbone. With the ability to route more energy directly to load centers in downtown LA and southern and southwestern neighborhoods without overloading other Victorville–LA lines, the Transmission Focus scenarios install substantially less utility PV + battery storage inside the basin, with RPM opting instead to build more cost-effective renewable energy outside the basin, including a large PV buildout north of LA in the Mojave Desert, at Rosamond. This is highlighted by the increased flow into the basin from Rosamond and Barren Ridge noted above in Figure 34 and the congestion on that path in the Transmission Focus – High Load Electrification scenario, which is apparent in Figure 37. It also indicates that in the other LA100 scenarios, congestion and/or contingency risk on the Victorville–LA path are driving the decision to build in-basin utility PV + battery projects.

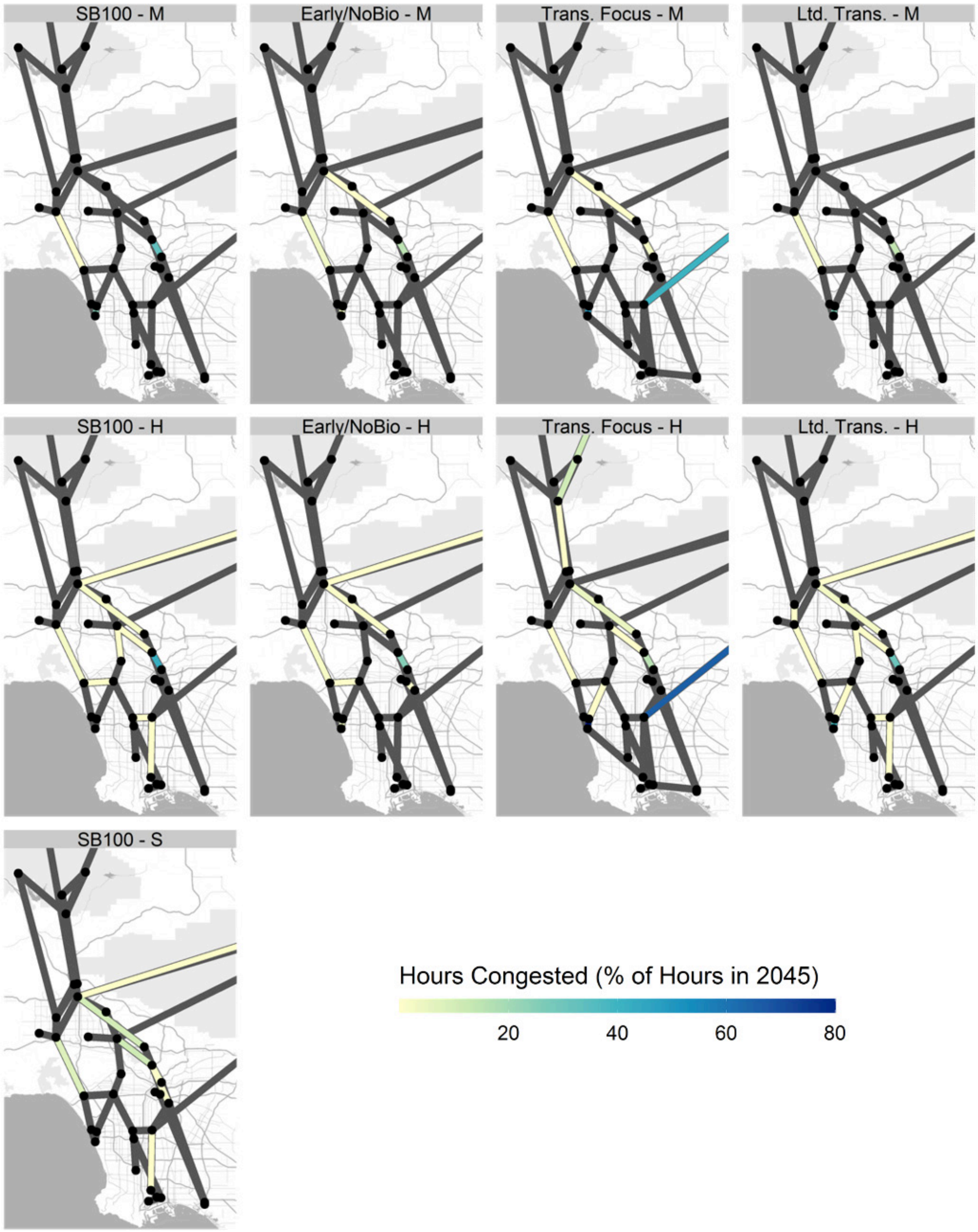

Figure 37. Congestion on in-basin and into-basin transmission paths in 2045 as a percentage of all hours in the year for all scenarios (except the 2017 IRP scenario, which is only modeled through 2035)

Lines colored gray experience no substantive congestion in the course of the year.

2.6 Looking Deeper: The Impact of Electrification and Load Flexibility

The LA100 scenarios demonstrate the potential importance of energy efficiency and energy use flexibility on reducing the need to build new capacity.

To illustrate this importance, we can compare the SB100 – High and Stress scenarios. These scenarios are identical with exception to their load assumptions. Specifically, the Stress projection assumes substantially lower energy efficiency and reduced load flexibility due to reduced participation in demand response programs (see Chapter 3, Electricity Demand Projections). For SB100 – High, the combined impact of improved efficiency and demand flexibility translates to a >3 GW reduction of capacity needed in 2045 when these measures are employed, as shown in Figure 38.

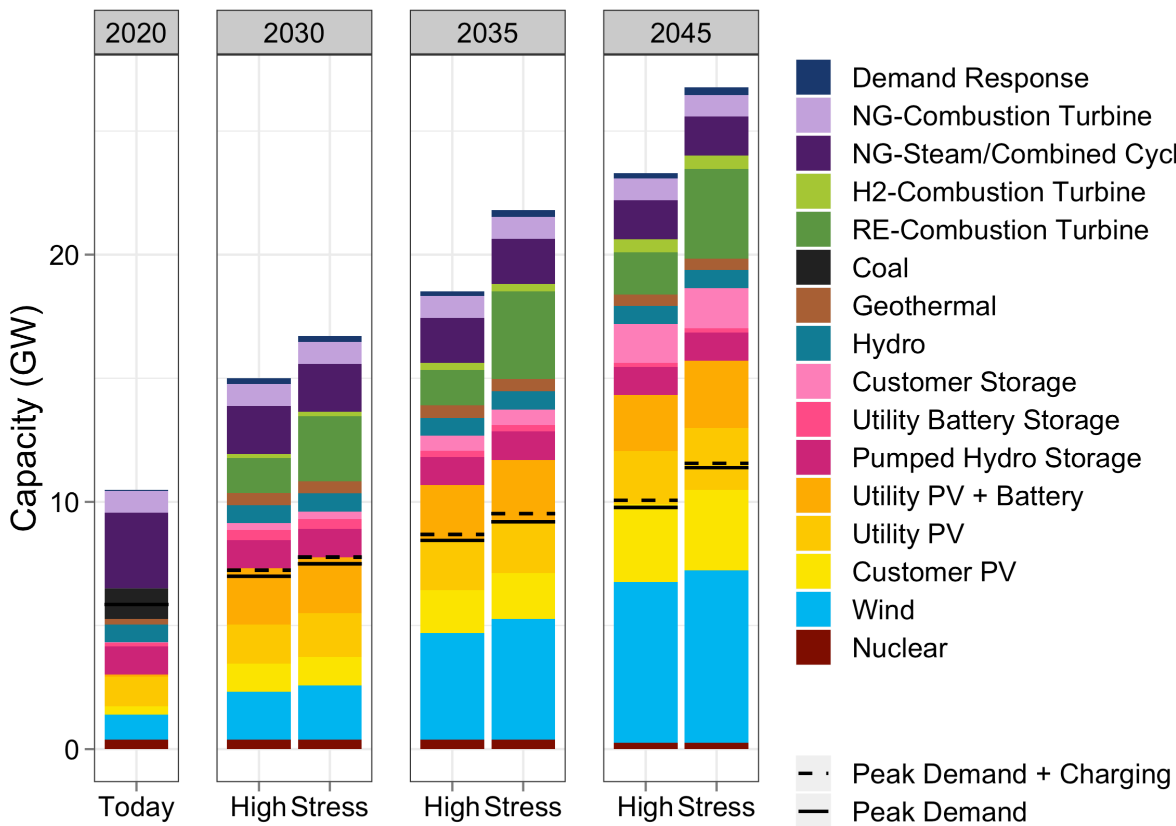

Figure 38. Comparison of total capacity between SB100 – High and SB100 – Stress

We can also see the operational benefits of flexible load in the hourly dispatch. Figure 39 illustrates how demand response can help LADWP maintain supply-demand balance even on days with lower than usual solar and/or wind availability. Load that would otherwise occur in the evening (thin solid line) is shifted into the morning and midday hours (shown as the dot-dash line), largely through shifted electric vehicle charging.[33] This shift reduces the need for renewable supply in the late afternoon and early evening (when solar resources have very low to zero output) and reduces stress across the power system. Load shifting associated with flexible

[33] 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, the power grid, and air quality and health.

load resources and demand response actually results in an increase in peak load as demand is shifted to times with surplus generation. Peak load increases from 8.5 to 9.4 GW and from 9.5 to 11.4 GW (depending on the scenario) under the Moderate and High load projections, respectively. After subtracting the variable renewable generation from total generation to get net load, however, we see that load flexibility and demand response decreases the peak load that must be served with dispatchable generation, from 6.8 GW to 5.3 GW and from 7.8 GW to 5.3 GW in Moderate and High scenarios, respectively.

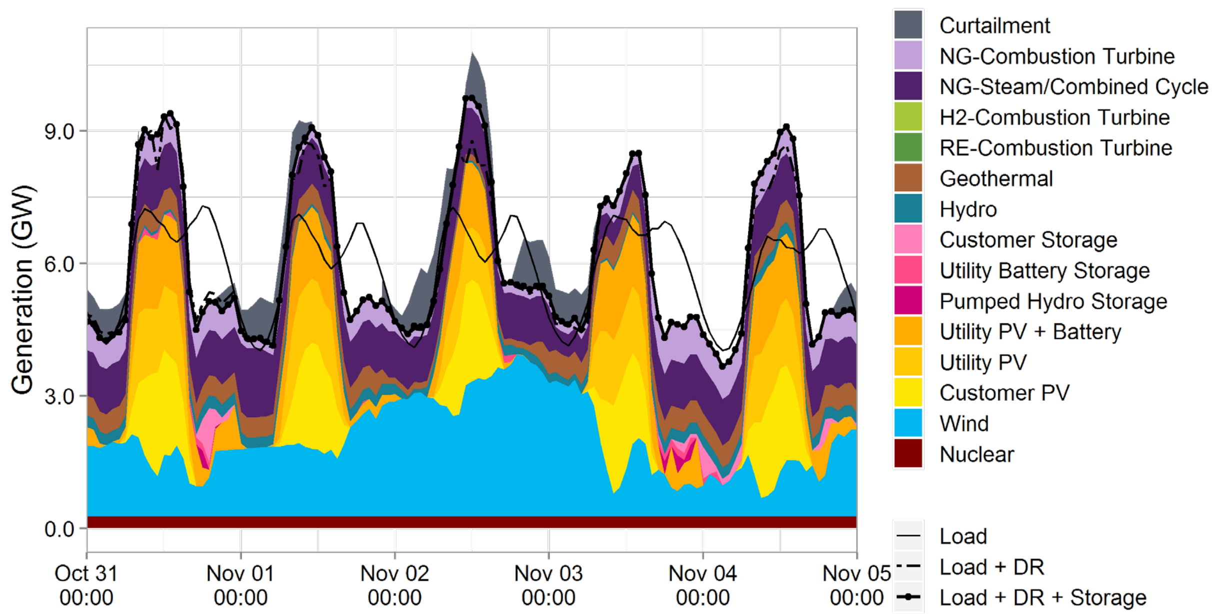

Figure 39. Hourly dispatch for five low wind and solar days in 2045, SB100 – High

2.7 Integration with California and the Western United States

The LA100 bulk investment analysis requires that LADWP own or contract for sufficient energy generation, storage, and transmission assets in order to meet all energy, capacity, and operating reserve requirements while achieving the 100% target. In other words, LADWP must be able to balance load independently. In addition, the core operational analysis assumes that LA is islanded from the rest of the WECC. For implementation in the PCM, we explicitly deleted all generators, nodes, and lines that were not part of the LADWP system. This effectively requires that all LADWP must be served only by LADWP generation in every hour and serves as our “base case” configuration for all runs.[34]

Nonetheless, LADWP is a relatively small part of a much larger, synchronous power system, the Western Interconnection of North America. Although LADWP is somewhat isolated (both geographically and electrically) it is nonetheless interconnected via AC and DC transmission lines to other regions and has the potential to exchange energy or other services with other balancing areas—indeed, LADWP does so already in their operations.

[34] As noted earlier, the sole exception to this requirement is that we allow some purchases of off-peak electricity for hydrogen production well in advance of when the fuel is needed for resource adequacy purposes.

We make this "islanded" assumption in the analysis as another step toward ensuring the adequacy of the system—if the system can be balanced independently, the option to access a broader market or trade with neighboring balancing authorities will only further increase reliability and has the potential to decrease costs (as opportunities to arbitrage across spatial and temporal differences in generation costs and load grow with greater numbers of participants). Indeed, the main purpose of the formation of the Western Energy Imbalance Market was to reduce costs of meeting energy requirements reliably.

In order to explore the potential impacts of coordinated operations of LADWP assets with the rest of WECC, we ran a PCM sensitivity that simulated just that—a perfectly coordinated market across WECC. We run this sensitivity on the Early & No Biofuels – High scenario. The sensitivity uses the same investment pathway (i.e., the identical generation, transmission, and storage resources), as the core scenario, but allows for both purchases and sale of energy between LADWP and any entity in the rest of WECC (subject to physical transfer limits and assumed hurdle rates between regions). The capacity of the rest of WECC was optimized using RPM simultaneously with the LADWP capacity expansion decisions, with decisions about total capacity built in each region made according to existing policy targets as of May 2018.

Figure 40 compares the annual generation for "integrated" operations and the base "physically islanded" case.[35] We observe three important changes to the generation mix. First, in the "WECC-Integrated" dispatch, renewable energy curtailment (shown in gray) is practically zero, while under the islanded case, curtailment is substantial across most of the study period. This near elimination of curtailment is due to the ability to export surplus wind and solar generation to neighboring regions.[36] Instead of this energy being unused it is exported to another region and used to help satisfy load (and potentially other renewable energy requirements). The second important change is that dispatch from H_2-CTs is drastically reduced in the integrated scenario. Instead of dispatch from H_2-CTs, purchased energy is relied on during the same periods. This is important because H_2-CTs represent the highest cost technology deployed in this scenario and the sharp reduction in the need to dispatch that resource may imply a substantial reduction in required capacity and associated cost of investment. Third, although integrated operations use imports to satisfy energy needs during some hours throughout the year, LADWP is a net exporter of energy, indicating a substantial opportunity for sales of surplus generation.

Even if LADWP does not join a formal market (imbalance market or CAISO), having the option to import and export power (as it does currently) can help reduce costs and displace the use of RE- or H_2-CTs.

[35] This particular comparison was based on a draft set of results; however, the results have not changed substantially, and the findings still hold.
[36] In the "WECC-Integrated" formulation of runs, the state renewable energy targets for California are reflected. Subject to physical power flow limits, the utilities and entities in California may be exporting power to neighboring states and entities during times of high renewable energy.

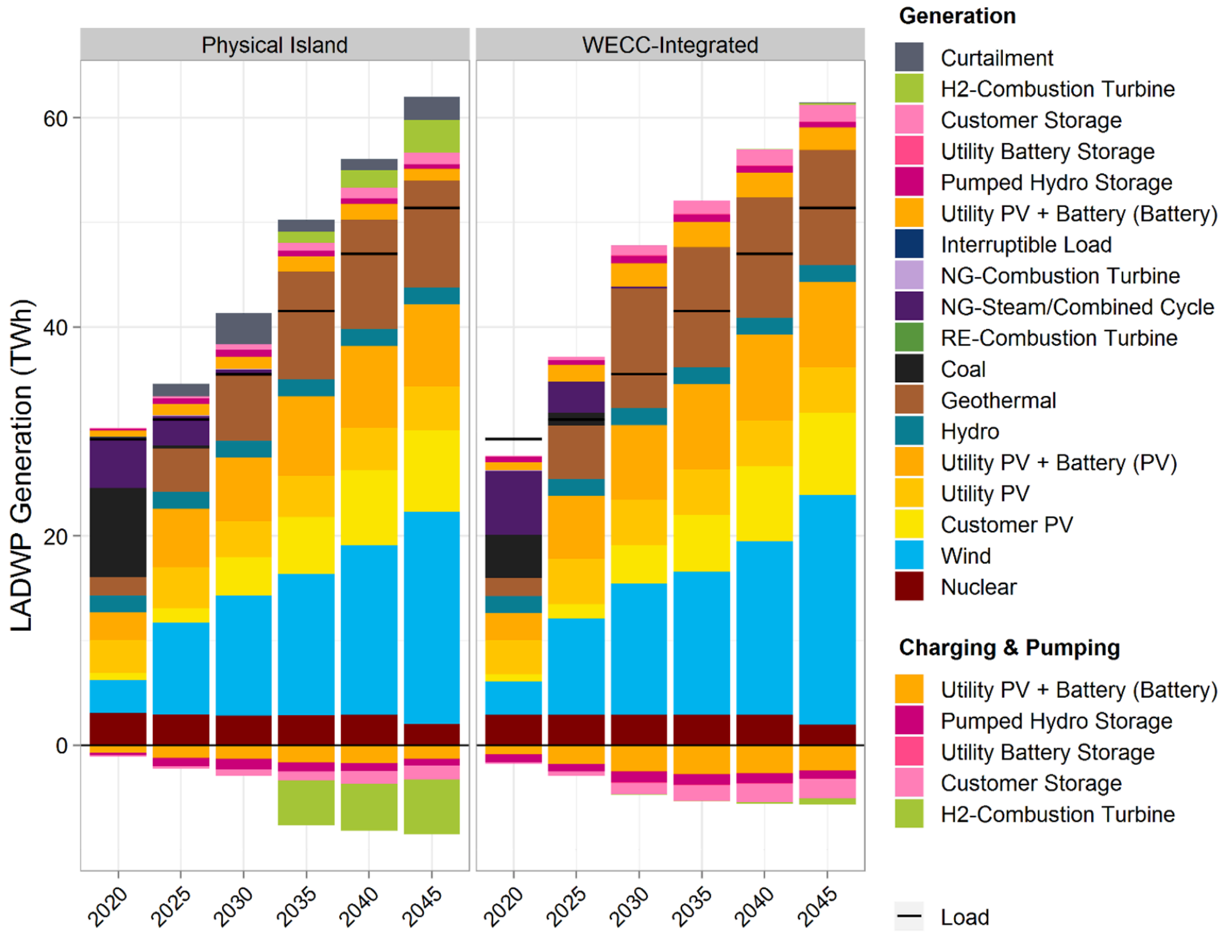

Figure 40. Annual generation for the Early & No Biofuels – High scenario when dispatching the LADWP system as a physically islanded system as opposed to a system able to exchange power with other regions in a "WECC-Integrated" dispatch

Negative values indicate the amount of electricity consumed by the plant (e.g., to charge a battery, pump hydro, or produce hydrogen fuel). Load (solid line) is customer electricity consumption exclusive of charging. Curtailment includes available energy that is curtailed to provide reserves.

3 How Much Does It Cost?

3.1 Cumulative Costs of the LA100 Scenarios

Transforming the LADWP power system to a 100% clean or renewable system would require large scale and rapid deployment of renewable resources and transmission both within and outside of the basin. Associated with the siting, construction, and operation of these resources are substantial costs. Here we present estimates of the costs associated with the technology investment pathways presented in Section 2.

Figure 41 shows the estimated cumulative (undiscounted) annualized costs[37] for each scenario (2021–2035 and 2021–2045) associated with bulk system generation and transmission investment and operations, customer sited solar PV installations, and distribution system upgrades required to accommodate load growth and distributed energy resources. Importantly, these cumulative costs do not include the cost of serving debt on any assets installed prior to 2021, future costs of distribution system O&M, or costs of energy efficiency and demand response programs.

[37] The costs presented are adjusted for inflation and are therefore presented in “real” terms (constant 2019$), but they are not present values—they are not discounted and therefore do not account for the time value of money. Rather, they represent the sum of the estimated cash-flow (including financing costs) over the period indicated. Debt service on any capital investments that continues beyond the 2045 study end-date is not included in these cumulative sums.

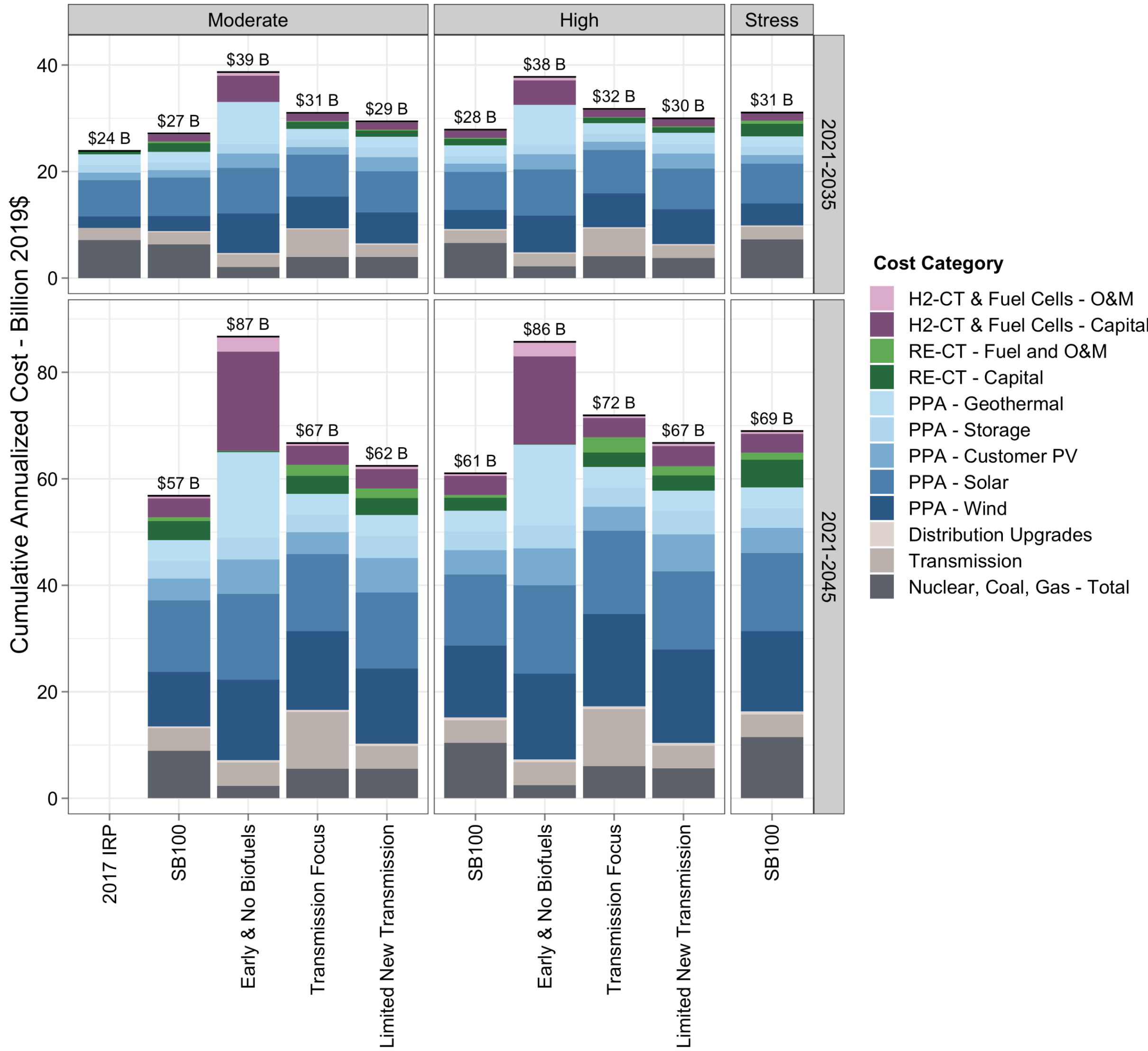

Figure 41. Cumulative annualized system costs incurred from 2021–2035 (top row) and from 2021–2045 (bottom row) by scenario, load level, and cost type

Costs shown include bulk power system investment and operations costs, customer rooftop solar installation costs, and distribution upgrade costs to accommodate load growth and distributed energy resources, but do not include debt payments on assets installed prior to 2021, future distribution costs related to operations.

These cumulative totals are made up of a mix of costs including capital or power purchase agreements (PPAs) for new generation, storage, transmission, and distribution assets, fuel costs for existing (natural gas, nuclear, and coal) assets and new (RE-CT) resources, and maintenance for all bulk-scale assets. We generally group these costs into four main categories: 1) total costs for existing thermal generation (including all fuel, O&M, and capital costs), 2) costs for transmission and distribution upgrades or new builds, 3) costs for PPAs for new wind, solar, geothermal, and battery storage assets,[38] and 4) capital, fuel, and O&M costs for new renewable firm capacity assets.[39]

Through 2035, cumulative costs across the four LA100 scenarios are estimated to range from approximately 27 billion 2019$ to 39 billion 2019$ depending on both the scenario specification and the load conditions. Comparing the core LA100 Moderate load scenarios to the IRP (through 2035) shows that the four LA100 scenarios represent increases in costs relative to the IRP (i.e., 2017 SLTRP Recommended Case). Percent cost differences from the IRP case are 14%, 62%, 30%, and 23%, for the SB100, Early & No Biofuels, Transmission Focus, and Limited New Transmission, respectively. These differences are driven by 1) the higher renewable/clean energy penetration achieved by 2035 in the LA100 scenarios and 2) the need to substitute the retired OTC capacity with alternative renewable resources in the LA100 scenarios.

Across the LA100 core scenarios, the costs of PPAs for new generation and storage assets make up the majority of total costs. This is consistent with the fact that the generation resources reflected in that cost category—wind, solar, geothermal—and the storage assets used to increase their utilization are responsible for the large majority of generation required to meet load. Wind, solar, and geothermal assets alone account for 73% to 90% of total energy generation by 2035 and 81% to 94% by 2045. Relative to the other core scenarios, Early & No Biofuels shows a substantially larger cost associated with PPAs—this is due to the increased deployment of predominantly geothermal assets to help meet the nearer term needs for energy and firm capacity resources as all existing natural gas assets are phased out by 2035.

Operating costs for existing thermal assets—coal, natural gas, and nuclear—remain a substantial but decreasing portion (over time) of cumulative costs, even as those assets are phased out (or limited, in the case of SB100) in the final compliance year. These costs represent the ongoing costs to fuel and operate these facilities as they continue to be relied upon to meet a portion of energy needs prior to the compliance year.[40] However, comparing the cost through 2035 and 2045, it is clear that the costs associated with these existing assets are greatly reduced across these scenarios, particularly under the Early & No Biofuels scenario where all fossil assets are retired by 2035. This reduction in costs is representative of reduced expenditures on fuel, emissions allowances, and other O&M costs.

Transmission and distribution upgrades and new builds account for a relatively consistent portion of total costs across the core scenarios, with exception of Transmission Focus. This consistency is due to a set of planned transmission upgrades that are uniform across all scenarios. Any differences in transmission costs across scenarios represents additional transmission builds beyond the planned upgrades. Across the SB100, Early & No Biofuels, and Limited New Transmission scenarios, total transmission and distribution costs range between $2 billion

[38] Wind, solar, geothermal, and storage assets account for the majority of energy production (and shifting) required to meet load, and such assets are typically procured by LADWP through PPAs. PPA costs are inclusive of curtailed energy.

[39] Firm capacity or "peaking" resources are used relatively infrequently—during times of system stress—and historically have been directly owned and financed by LADWP; as such, we disaggregate the costs of those resources into two subcategories: capital costs and operational costs, the latter of which includes fuel and O&M.

[40] SB100 allows a portion of energy needs to be met with natural gas if offset with purchased RECs and that both SB100 and Early & No Biofuels allow nuclear to contribute to energy needs through 2045.

(2019$) and $3 billion (2019$) through 2035, and $4 billion (2019$) and $5 billion (2019$) through 2045. Under Transmission Focus, which assumes the construction of a large out-to-in-basin DC line and associated in-basin DC connections to help distribute energy being imported with that line, transmission costs are substantially higher—totaling approximately $11 billion (2019$) through 2045.

The last major cost category represents the cost of investment in and operation of renewable firm capacity or peaking assets—RE-CTs, H_2-CTs, and fuel cells. Across SB100, Transmission Focus, and Limited New Transmission Moderate and High scenarios, these range from $7 billion (2019$) in the SB100 – High scenario to nearly 10 billion 2019$ in the Transmission Focus – High scenario. The lower range of costs is associated with the SB100 scenarios that exhibit lower levels of investment in and utilization of renewable firm capacity resources. The Early & No Biofuels scenario shows substantially higher firm capacity resource costs than the other core scenarios: approximately 22 billion 2019$ in both the Moderate and High scenarios; these costs are associated with the greater level of investment in H_2-CT assets beginning with the 2035 compliance year.

Among the LA100 scenarios, SB100 shows the lowest overall costs in both 2035 and 2045. This is driven by the fact that 1) the 100% target in SB100 is based on load instead of generation (the other core LA100 scenarios use generation as the basis), and 2) the SB100 scenario allows the use of unbundled renewable electricity credits for a portion (10%) of compliance. The load basis of the target slightly lowers the effective stringency, and the RECs provide additional flexibility for compliance, which in combination lead to lower overall levels of investment in new resources and lower compliance costs with the 100% target. These results show that using a load-based definition and allowing the use of unbundled RECs to account for a portion of compliance are both mechanisms that could be employed to lower the overall cost of compliance. However, it is also important to recognize that both these mechanisms reduce the overall level of renewable energy used to meet LADWP's electricity service requirements.

The Early & No Biofuels scenario shows the highest costs in both the 2035 and 2045 timeframes: 35%–42% higher than SB100 in 2035 and 40%–52% in 2045, depending on the load conditions. This increase is driven by the higher target—100%—in 2035, along with the restriction that renewably fueled CTs (which assume market-purchased biofuels through 2040) cannot be used as a capacity resource until 2045, when the fuel is assumed to be hydrogen. As a result, this scenario must rely on less mature and higher cost technologies in the mid-term to supply in-basin capacity, namely dedicated plants that produce and combust hydrogen, along with greater deployment of out-of-basin firm capacity, predominantly geothermal.

3.2 Annual, Normalized, and Incremental Costs

Section 3.1 presented estimated cumulative costs by category over the analysis period. Here we present the same set of costs but aggregated across cost categories shown in Figure 41 and by year. We present both annualized and cumulative costs as total values and normalized by electricity generated. As with the above cost metrics, in all scenarios "total costs" here refers to costs associated with bulk system generation and transmission investment and operations, customer sited solar PV installations, and distribution system upgrades beginning in 2021, and excludes the costs of serving debt on any assets installed prior to 2021, future costs of distribution system O&M, and costs of energy efficiency and demand response programs.

Figure 42 shows four different metrics over time. Annual costs (*upper left*) represent the total costs observed in a given year—this includes operational costs in that year (e.g., fuel and O&M), payments of any existing PPAs, and accumulated debt service associated with capital investments in that year as well prior years. Cumulative costs (*bottom left*) show the total costs over all years through the year of interest—i.e., it is a running sum of annual costs. Average annual costs of generation (*upper right*) normalizes the annual costs over annual generation and thus reflects the average cost of generation in a given year and controls (partly) for the differences in load across years and scenarios. Finally, cumulative average cost of generation (*lower right*) normalizes total cumulative costs (through any given year) by the sum of generation across the same set of years, and thus reflects the average costs of generation over all years from 2021 through the year of interest.

Across all scenarios, annual costs generally increase over the analysis period. This occurs for a number of reasons. First, because the analysis does not capture existing debt or PPAs (on assets that came online prior to 2021), costs in 2021 represent the annualized cost of a single year of new resources. As more resources are deployed in future years, costs grow as the annualized cost of resources installed in both the current year and prior years are reflected. Second, load is growing. Over the analysis period, end-use load grows at a compound annual growth rate of 1.6% in Moderate, 2.3% in High, and 2.6% in Stress load scenarios. All else equal, this load growth leads to the need for additional assets. Third, and perhaps most importantly, as we move forward in time the requirement for higher levels of renewable generation drives investment in new resources to replace existing non-renewable assets.

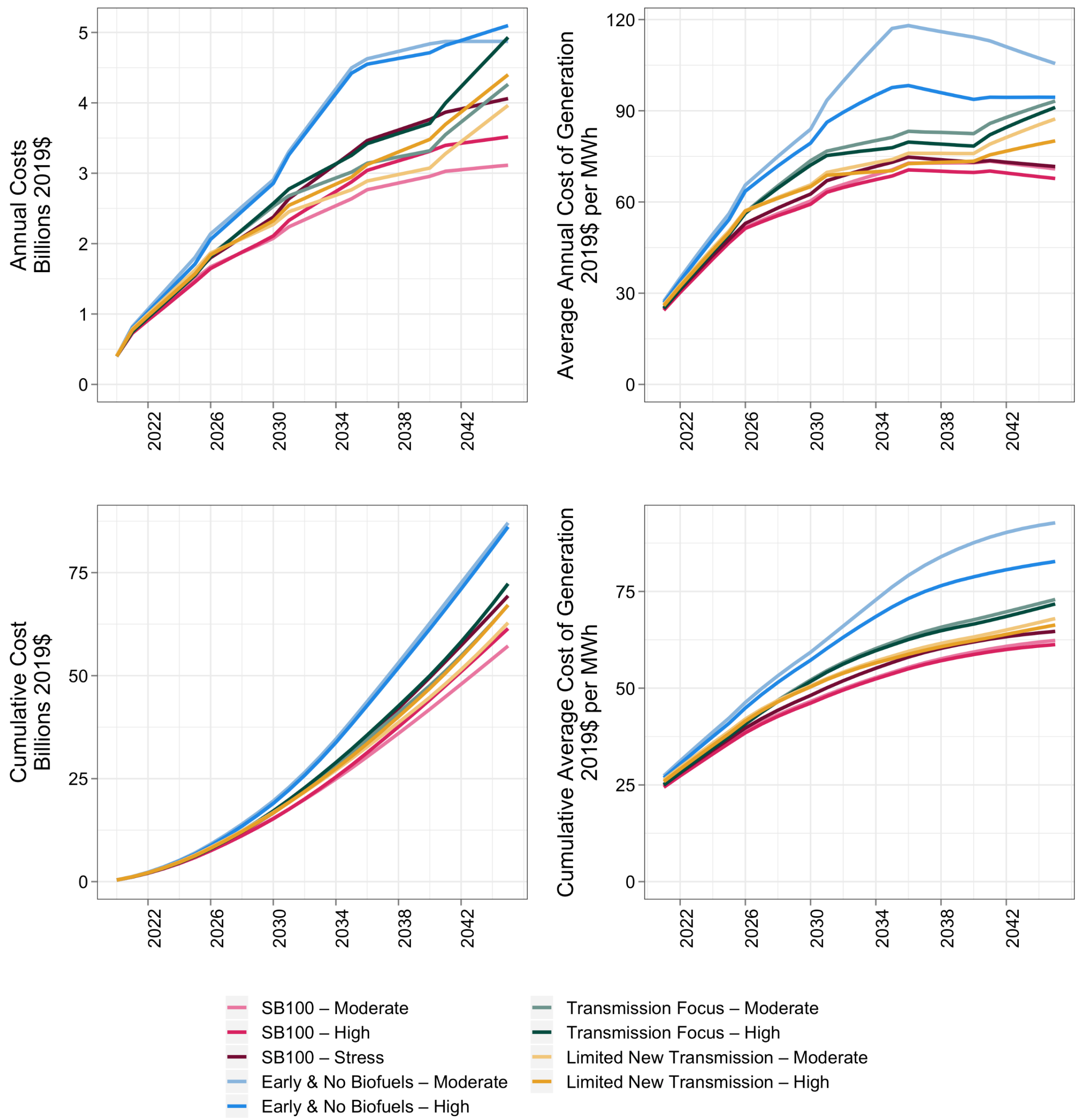

Figure 42. Annual and normalized costs of generation over time

Annual costs (upper left) represent the total costs observed in a given year (operations, PPA payments, annualized capital costs from LA100 resources installed in earlier years). Cumulative costs (bottom left) show the total costs over all years through that year. Average annual costs of generation (upper right) normalize the annual costs over annual generation. Cumulative average cost of generation (lower right) normalizes total cumulative costs by the sum of generation across the same set of years.

Under the Early & No Biofuels scenario annual costs increase relatively sharply between 2030 and 2035. This is driven by the suite of investments required to achieve the 100% targets in 2035. In 2030, Early & No Biofuels has achieved approximately 98% clean generation (including both renewable and nuclear resources). *Yet, to increase generation from the 98% clean system in 2030 to a 100% clean system in 2035, substantial investment is required.* New wind, solar, and diurnal storage assets are deployed to help meet the increased energy needs, but the majority of the investment is comprised of in-basin H_2-CTs, which are deployed to meet firm capacity needs that were historically met with in-basin fossil units. These investments drive a substantial increase in annual costs due to their relatively high cost. Following 2035, annual costs plateau as the system has already achieved the 100% target, and new investment is solely required to accommodate load growth and retirement of any other generation or storage assets.

Annual costs under the SB100, Transmission Focus, and Limited New Transmission exhibit similar behavior to each other through 2040. This is consistent with the fact that these scenarios, despite having some differences—in target definition, customer PV deployment, and transmission—all achieve approximately 90% renewable generation by 2035 (Table 13). However, beginning in approximately 2040 we observe a divergence between SB100 and the other two scenarios. SB100 remains relatively constant with slight growth in costs to accommodate load growth, while Transmission Focus and Limited New Transmission both exhibit sharp increases in cost, similar to the behavior of Early & No Biofuels in the 2030–2035 timeframe. Again, here we are seeing the impacts of the costs associated with achieving the last few percent of the 100% target. In 2040, the Transmission Focus and Limited New Transmission scenarios both have renewable and carbon-free generation fractions of approximately 90% (inclusive of nuclear); the increase in annual costs represents the cost of the additional investment required to achieve the 100% renewable system in 2045, including replacing the nuclear generation. Certainly, these investments are also driven by load growth over the same time frame, but the fact that the average annual cost of generation diverges from SB100 despite similar load, indicating that the change in the renewable target is the predominate driver.

Table 13. Total Clean Energy (Renewable, Hydro, and Nuclear) Penetration Achieved Across Scenarios in 2035 and 2045

Scenario	Load	2035	2045
IRP	Moderate	77%	
SB100	Moderate	90%	90%
Early/NoBio	Moderate	100%	100%
Trans. Focus	Moderate	90%	100%
Ltd. Trans	Moderate	91%	100%
SB100	High	84%	88%
Early/NoBio	High	100%	100%
Trans. Focus	High	89%	100%
Ltd. Trans	High	90%	100%
SB100	Stress	85%	87%

Despite the clear increase in annual costs associated with increasing the share of renewable or clean generation from above 90% to 100%, it is important to recognize that this analysis does not allow for a precise calculation of the marginal or incremental cost of increasing the renewable or clean energy share. Recall that the annual costs shown here include the cost of servicing accumulated debt and PPA obligations. Precise evaluation of the marginal or incremental costs would require a much more stylized scenario framework that held all aspects of a set of sensitivities constant except for the renewable target and varied that renewable target in small increments.

3.3 Sensitivity Analyses

The core LA100 scenarios were designed to explore alternative technology pathways to achieving a 100% renewable or clean system and reflected priorities and questions from the LA100 study's stakeholders. However, with each scenario reflecting multiple differences from other scenarios, it can be difficult to isolate the effects of individual drivers of results. To explore some of these drivers and estimate their relative impacts we simulated a set of sensitivities that varied single aspects of the some of the core scenarios. In addition, we ran sensitivity analyses to assumptions that are common to all scenarios, such as technology prices, to understand the robustness of results against these assumptions.

We identified five key issues that can shape the technology pathways and associated costs to reaching the 100% renewable energy. These issues include the scope of the 100% target; the definition of "renewable energy" in the target; the speed of the transition (2035 vs. 2045); feasibility of new infrastructure; and technology costs. These sensitivities can help us explore the dependency of results on these different assumptions.

3.3.1 Scope of the 100% Target

Senate Bill 100 requires that by 2045 renewable generation is equal to or exceeds 100% of electricity sales. The key aspect of this is that the target is based on sales. Sales reflect the total amount of energy that is purchased by customers, but, importantly, in order for electricity to arrive at customers' plugs, it needs to be transmitted from the generators through the transmission and distribution network to the end-use customers. In this transmission of electricity from point of generation to point of use, there are energy losses due to the natural and unavoidable inefficiencies in transmission. As a result, total generation typically exceeds end-use sales by anywhere from 5%–15%. Establishing a target based on a percent of sales instead of generation therefore lowers the overall stringency of the target: 50% of 100 MWh is less than 50% of 110 MWh. Conversely, a target that is based on total generation is slightly more stringent than one covering retail sales. In the LA100 study, the SB100 scenario captures to the closest degree possible the specifics of the SB100 policy, and therefore the target is based on retail sales; the other core scenarios are based on total generation, including losses. To explore how this change in the target definition impacts results, we ran a sensitivity that was identical to the core SB100 but formulated the target based on generation instead of sales. Table 14 summarizes the sensitivity definition and Figure 43 illustrates the impact of this sensitivity.

Table 14. Target Definition and Compliance Sensitivities

Core Scenario	Sensitivity Name	Sensitivity Definition
SB100 High	SB100 - Gen. Based Target	The 100% target is based on total generation instead of sales; this creates a more stringent target

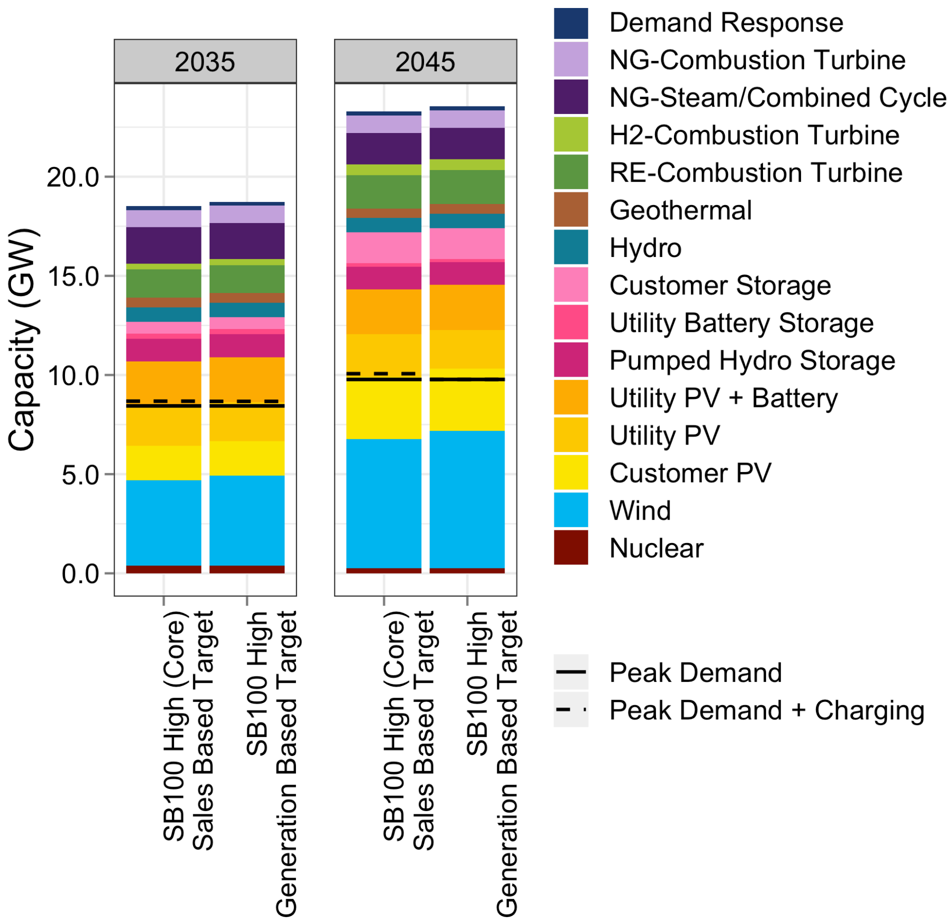

Figure 43. Impacts of changing the scope of the 100% target between retail sales and generation

The increase in the target stringency associated with the change in the basis of target from sale to generation had a small but noticeable impact on the technology buildout. Under the generation-based target, additional wind capacity is deployed to meet the slightly higher renewable energy requirement by 2035, with an additional increase in 2045, as seen in Figure 44. However, the system remained similar to the core scenario. These changes led to a less than 1% increase in cumulative costs through 2045. The limited change in capacity buildout and associated costs is partly due to the fact the SB100 scenario retains the flexibility to use RECs as a portion of compliance.

3.3.2 Eligibility of Technologies and Alternative Compliance Mechanisms

Another key determinant of the technology pathway to 100% renewable energy is the eligibility of technologies—what counts as a renewable technology—and whether alternative compliance options exist that effectively allow limited generation from non-renewable sources such as natural gas. For example, eligibility addresses whether non-renewable zero-carbon emissions technologies (such as nuclear) or net-zero emitting technologies (such a biofuels) can contribute to the 100% renewable energy target. On alternative compliance options, Senate Bill 100 currently allows the use of unbundled renewable electricity credits (RECs) to account for a portion of the clean energy target. This flexibility in compliance allows non-renewable sources to be used to meet energy and/or capacity needs so long as any generation is offset by a purchased unbundled REC, and that REC limits are not exceeded (which are currently set at 10% under Senate Bill 100).

In the LA100 study, the SB100 scenario—following the current stipulation under the formal policy—is allowed to use RECs for a portion (10%) of compliance through 2045. Transmission Focus and Limited New Transmission scenarios allow use through 2044, and Early & No Biofuels through 2034. The allowance of RECs allows SB100 to maintain natural gas. Disallowing RECs (and making the target based on generation and not retail sales) requires the scenario to retire its fossil fleet. The core scenarios also vary by technology eligibility, particularly with respect to biofuel and nuclear technologies.

To explore the impact of both the eligibility of biofuel technologies and the RECs for a portion of compliance, we simulated sensitivities to the SB100 and Early & No Biofuels scenarios. The sensitivities in this section are summarized in Table 15. The SB100 sensitivity disallows the use of RECs, and, as a result, fossil capacity cannot be used to meet energy, operating reserves, or long-term capacity needs in 2045. All fossil capacity is thus retired by 2045. In the opposite direction, a sensitivity to Early & No Biofuels allows the use of RECs through 2044, which in turn allows natural gas but not biofuels to contribute to 10% of the target through 2044. By 2045, however, the Early & No Biofuels scenario must achieve 100% without the use of RECs. The third sensitivity evaluates Early & No Biofuels with its original 2035 compliance year but includes biofuel technologies as eligible.

Table 15. Target Definition and Compliance Sensitivities

Core Scenario	Sensitivity Name	Sensitivity Definition
SB100 – High	SB100 - Gen. Based Target & No RECs by 2045	The 100% target is based on generation and RECs are not allowed in 2045 compliance year; fossil cannot provide energy or capacity resources
Early & No Biofuels – High	Early & No Biofuels with RECs	Natural gas via unbundled RECs is allowed to be used to satisfy up to 10% of the target through 2044; biofuels still not allowed; no RECs are allowed in 2045
Early & No Biofuels – High	Early & No Biofuels with RE-CTs	Renewable combustion turbines (i.e., biofuels through 2040; hydrogen in 2045) are allowed in all model years

Figure 44 summarizes the results of these sensitivities.

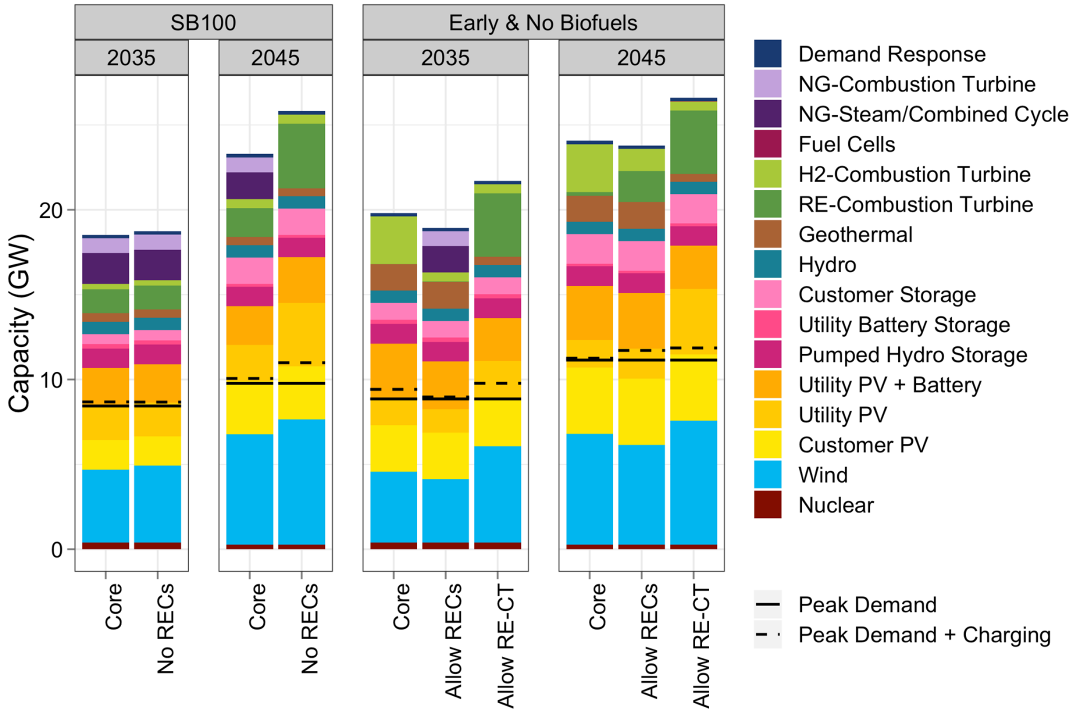

Figure 44. Capacity impacts of target definition and compliance sensitivities

SB100 No RECs

When unbundled RECs are not allowed in the SB100 – High scenario, there is little change in 2035, but by 2045 with the target reaching 100%, all natural gas capacity is retired. As a result, additional RE-CT capacity in conjunction with new wind and solar is deployed to make up for the lost natural gas capacity and associated natural gas generation in the core scenario.

Although the impact of the allowance of RECs on the resource mix of the SB100 scenario is substantial, the associated cost impacts through 2045 are not as pronounced. Through 2045, we observe an increase of ~2% in cumulative cost.[41] One of the main reasons for this relatively low value, however, is that these costs reflect cumulative annualized capital expenses of investments through the year of interest (in this case 2045). If a resource comes online in 2045, then only a single year of the annualized costs are included, despite the fact that much of the asset's financial lifetime will incur after 2045. Given that we observe a substantial amount of investment in RE-CT, solar, and wind resources between 2044 and 2045 in this sensitivity, this end-year effect has a substantial impact. If we calculate cumulative costs through the end of all assets' financial life (2074) instead of through 2045, we observe a ~18% difference in cost.

[41] We use the capacity model (RPM) to evaluate the sensitivities in this section, without validating operations through the additional step of the production cost model. The cost impacts reflect capital and operational costs based on RPM for both the core and sensitivities. Because RPM's operational costs are a coarser estimate compared to the PCM, we therefore use a ~ to emphasize that the cost impacts are approximate.

Early & No Biofuels with RECs

Examining the sensitivity to Early & No Biofuels that allows the use of RECs through 2044, we similarly see changes predominantly in the renewable firm capacity resources located in basin. Given the availability of RECs, the non-OTC natural gas capacity remains online instead of retiring in 2035. This avoids the need for the substantial investment in H_2-CT technologies in 2035 and also reduces the amount of wind and solar capacity required. In 2045, while H_2-CT capacity is still utilized, RE-CTs make up a much larger portion of capacity given that early investment in H_2-CTs was not necessary, thereby avoiding the lock-in of that technology type. Recall that RE-CTs are allowed under the core Early & No Biofuels scenario in 2045 as the fuel is assumed to be transitioned to hydrogen. Avoiding these early investments in H_2-CTs and reducing the overall amount of H_2-CTs utilized reduced the costs from the core scenario by ~17% through 2045.

Early & No Biofuels with RE-CTs

Finally, examining Early & No Biofuels sensitivity maintains the 2035 target year but allows biofuels shows similar results: predominantly substitution of firm capacity assets. Relative to the core scenario, instead of H_2-CTs and geothermal capacity providing necessary firm capacity with retirement of the natural gas resources, RE-CTs are deployed in 2035 and remain the core in-basin firm capacity asset through 2045. The cumulative cost of this scenario through 2045 is ~21% lower compared to the base scenario of no biofuels; rising to a ~26% reduction if the full financial lifetime costs (through 2074) are included.

Both Early & No Biofuels sensitivities demonstrate that costs can be substantially impacted by the eligibility of technologies. Restricting eligibility of technologies limits options for compliance and can result (as shown by the core scenarios and sensitivities) in substantial cost impacts. Alternatively, creating flexibility, such as through the allowance of limited use of unbundled RECs, effectively creates technology optionality—allowing limited generation from any technology type—and represents a mechanism to mitigate costs of compliance.

3.3.3 Speed of Transition

The speed of the transition to a 100% renewable or clean system can impact both the mix of technologies deployed as well as the associated costs of compliance. To evaluate the implications of the timing of the 100% target compliance year, we simulated the Early & No Biofuels, Transmission Focus, and Limited New Transmission with target years of both 2035 and 2045 (summarized in Table 16). Given that the core Transmission Focus and Limited New Transmission scenarios both use 2045 as the 100% target year, we simulate sensitivities of those scenario with a 2035 target. For Early & No Biofuels, since the core scenario has a compliance year of 2035, we simulate Early & No Biofuels with a compliance year of 2045.

Table 16. Speed of Transition Sensitivities

Core Scenario	Sensitivity Name	Sensitivity Definition
Early/NoBio – High	Early/NoBio Compliance Year 2045	Natural gas (via unbundled RECs) is allowed to be used to satisfy up to 10% of the target through 2044; no biofuels; no RECs are allowed in 2045 (described in the previous section)
Trans. Focus – High	Trans. Focus Compliance Year 2035	RECs (and therefore fossil generation) are not allowed starting in 2035
Ltd. Trans. – High	Ltd. Trans. Compliance Year 2035	RECs (and therefore fossil generation) are not allowed starting in 2035

Figure 45 shows the impacts of altering the compliance (or target) year on the capacity mix. From the results it is clear that moving the compliance year has a fairly strong impact on the 2035 capacity mix. A compliance year of 2035 requires that all natural gas capacity is retired by 2035, and thus services provided by those resources—energy, capacity, or operating reserves—must be replaced. Under the scenarios that treat RE-CT as an eligible renewable technology, we see that RE-CT, coupled with increased wind and solar builds, makes up for the retired natural gas capacity. But, under the Early & No Biofuels scenario, where RE-CT is not eligible until 2045, natural gas resources are replaced with a combination of H_2-CT, wind, and solar plants. By 2045, the capacity differences driven by compliance year changes are much smaller—effectively negligible under the Transmission Focus and Limited New Transmission scenarios. This is not surprising, as irrespective of the compliance year, all scenarios achieve the 100% target by 2045, and in the cases of Transmission Focus and Limited New Transmission, the earlier compliance scenarios solely had an effect of accelerating investment in RE-CT assets.

However, Early & No Biofuels does show some important differences in 2045. When the compliance target is extended to 2045, the resulting system has substantially fewer H_2-CT resources, and substantially more RE-CT. This is driven by the assumption that by 2045, RE-CT resources are fueled with hydrogen and therefore eligible as a renewable technology. Prior to 2045 RE-CTs are assumed to be fueled with a bio- or other carbon-based fuel and therefore ineligible under this scenario. Extending the target year to 2045 thus expands the technology options that can be used for compliance, and given that RE-CTs represent a lower-cost firm capacity option than H_2-CTs, they are deployed in favor of H_2-CTs in that final compliance year.

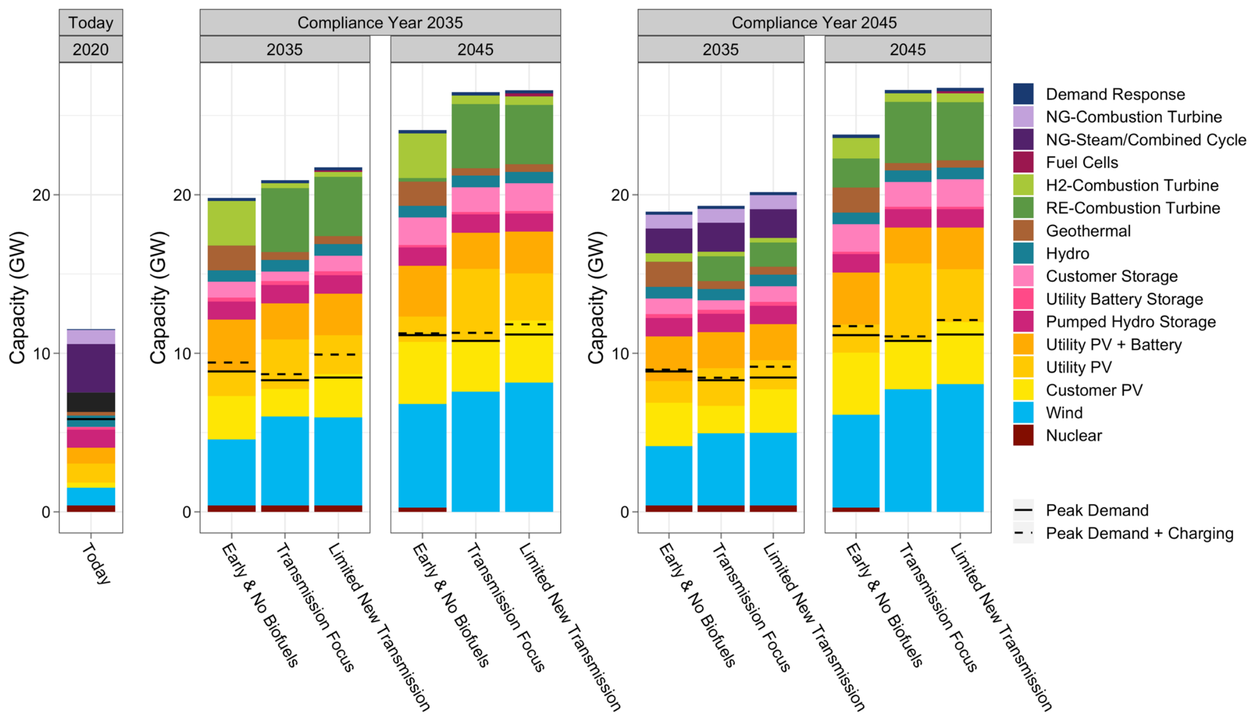

Figure 45. Capacity impacts of speed of transition sensitivities

Figure 46 shows the cumulative costs through 2035 and through 2045 for the same set of sensitivities. As can be seen in the figure, altering the compliance year has cost implications in the 2035 timeframe that persist (and grow) through 2045. Extending the compliance year under the Early & No Biofuels scenario from 2035 to 2045 can lower cumulative costs by ~17% through 2045. For the Transmission Focus and Limited New Transmission scenarios, moving the compliance year forward from 2045 to 2035 increases cumulative costs through 2045 by ~7% and 8%, respectively.

This sensitivity analysis did not include production cost modeling, analysis of reliability, resiliency to long duration outages, or feasibility of construction of the scenarios. As a result, the results are solely indicative of the estimated capital and operational costs associated with the scenarios achieving their 100% target in the alternative compliance year.

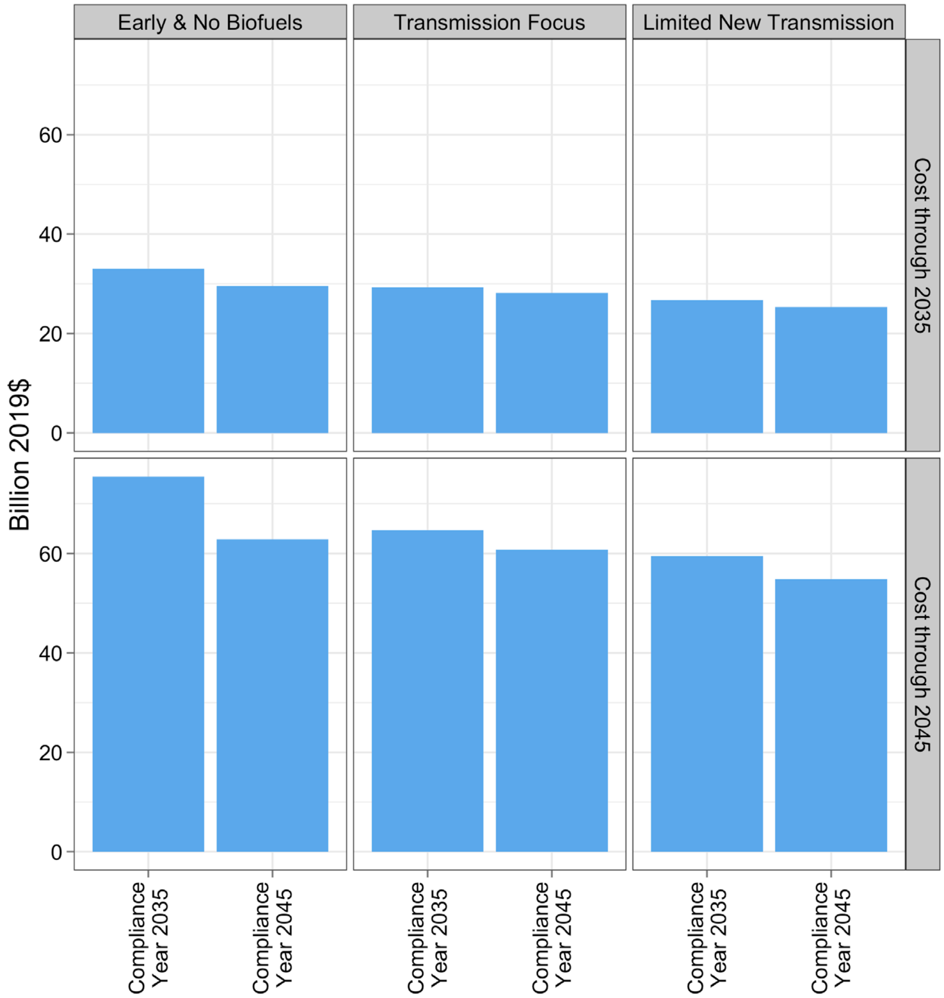

Figure 46. Cumulative capital and operational costs through 2035 (top row) and 2045 (bottom row)

These costs do not include distributed PV costs or distribution upgrades.

3.3.4 Feasibility of New Infrastructure

The core scenarios require a rapid buildout of both generation and transmission assets. Across the core scenarios, the average rate of deployment of combined wind and solar assets is 410–590 MW/year from 2021 through 2035 and 150–750 MW/yr from 2036 through 2045, depending on the specific scenario and load conditions. In-basin RE-CTs and H_2-CTs also must be sited and constructed rapidly, with between 1.5 and 2.5 GW constructed by 2035 and a total of 1.5–5.2 GW by 2045, across the Moderate and High load scenarios. Additionally, a number of in-basin transmission upgrades and new builds are identified: these range from a single, 3-km (1.9 mile) line in the SB 100 Moderate scenario, to five lines in the SB 100 Stress scenario comprising 46-km (29 miles) of transmission. In addition to these model-identified transmission builds, the Transmission Focus scenario also assumes the construction of a DC line from Victorville to Century and new DC ties to interconnect Century to the three southern thermal generation sites: Harbor, Haynes, and Scattergood. These new DC lines alone represent approximately 165 km (103 miles) of new DC transmission.

To explore the implications of more limited availability and/or feasibility of construction of different types of infrastructure, we simulate a set of scenarios that restricts the deployment of specific technologies. The sensitivities analyzed, described in Table 17, include identical sensitivities on Early & No Biofuels, Transmission Focus, and Limited New Transmission that do not allow any type of in-basin combustion or fuel cell technology (i.e., no RE-CT, H_2-CT, or fuel cells can be deployed in the LA Basin). Additionally, we simulate a sensitivity on Transmission Focus that instead of forcing in the DC transmission backbone, the sensitivity allows it as an option (with associated costs). Finally, although not reported here, the Limited New Transmission core scenario shows the impacts of limiting transmission builds to only currently planned transmission upgrades on system evolution.

Table 17. Tradeoffs in Large-Scale Infrastructure Sensitivities

Core Scenario	Sensitivity Name	Sensitivity Definition
Early & No Biofuels – High	Early/NoBio No In-Basin Combustion	No new combustion turbines (H_2 or other fuels) or fuel cells can be sited in basin
Transmission Focus – High	Trans. Focus No In-Basin Combustion	No new combustion turbines (H_2 or other fuels) or fuel cells can be sited in basin
Limited New Transmission	Ltd. Trans. No In-Basin Combustion	No new combustion turbines (H_2 or other fuels) or fuel cells can be sited in basin
Transmission Focus – High	Trans. Focus No Prescribed Backbone	The DC backbone is allowed to be built, but is not required to be built

Figure 47 shows the results from the sensitivities to the Early & No Biofuels and Transmission Focus scenarios. Results are disaggregated by location (in-basin resources shown in the top row and out-of-basin resources shown in the bottom row). Results from the Limited New Transmission sensitivity that does not allow in-basin H_2-CTs, RE-CTs, or fuel cells are not included because that scenario could not be solved by the model—the scenario was infeasible. This indicates that achieving a 100% renewable system under a future in which transmission upgrades are infeasible and new in-basin H_2-CTs, RE-CTs, or fuel cells are either ineligible or are not technically feasible, would be highly technically challenging and perhaps infeasible, without substantial increases in energy efficiency, demand response, and/or other mechanisms to address periods of transmission outages or low renewable energy availability.

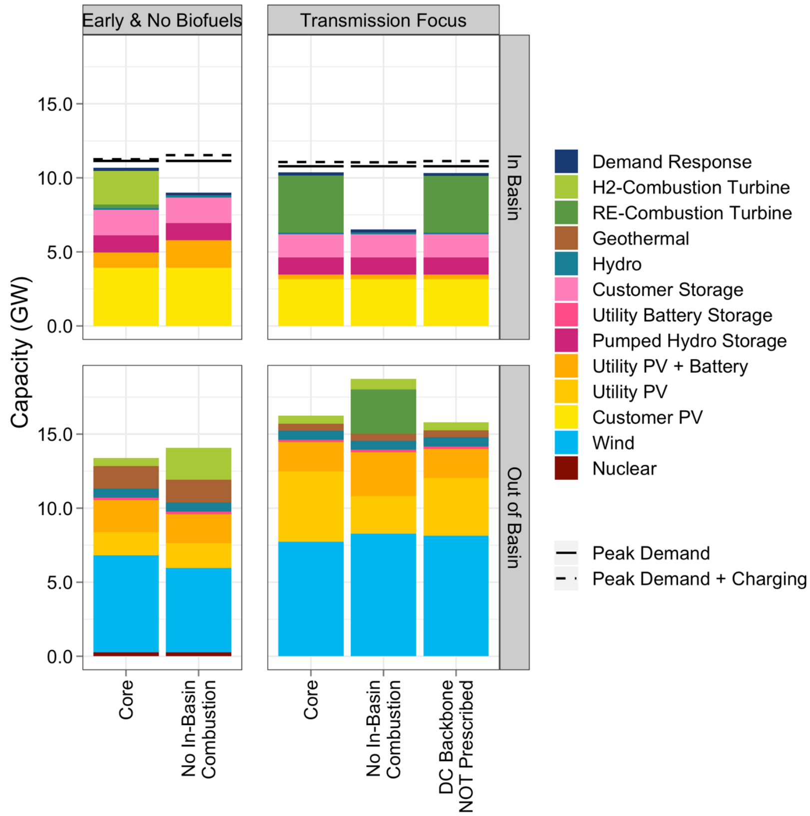

Figure 47. Capacity impacts of feasibility sensitivities

Resources are separated into capacity located within the LA Basin (top row) and outside of the LA Basin (bottom row).

Under the Early & No Biofuels scenario, disallowing the deployment of in-basin H_2-CT, RE-CT, and fuel cell resources has a pronounced impact on capacity investments. Under the core scenario, the system is characterized by deployment of 2.5 GW of combined in-basin H_2-CT and RE-CT capacity, none of which is allowed to be built in the No In-Basin Combustion sensitivity. In particular, this creates a challenge in meeting the local capacity requirements—i.e., supplying the in-basin resources required to serve load during times of system stress. Under the sensitivity, these capacity needs are addressed with two key changes. First, additional in-basin PV + battery resources are deployed along with some additional stand-alone battery storage. These resources, although only supplying diurnal (2–12 hour duration) storage, make up for some of the lost firm capacity relative to the core scenario. Second, the H_2-CT and RE-CT capacity is shifted out of basin and additional transmission upgrades are executed to allow energy from these out-of-basin resources to be transmitted to the load centers within the LA Basin. The additional transmission upgrades increase both within-basin transmission capacity as well as out-of-basin transmission capacity but are concentrated within basin (see Table 18. Transmission Investments for Each Investment Sensitivity). This is largely due to the fact that even within the Early & No Biofuels core scenario, out-of-basin transmission upgrades are already substantial and thus little additional out-of-basin transmission capacity is needed.

Under the Transmission Focus No In-Basin Combustion sensitivity, we see similar behavior. Disallowing the deployment of RE-CT, H_2-CT, and fuel cells shifts those assets from within basin to out-of-basin, and this is further supported by predominantly in-basin (and highly flexible) transmission upgrades to help move energy around the LA Basin from the main points of receipt (from out-of-basin). The cumulative through 2045 cost impact of this sensitivity is an increase of ~1% over the core scenario.

The second Transmission Focus sensitivity, instead of forcing the construction of the DC transmission backbone, specifies the resource as an option that can be constructed and allows the model to choose the capacity (size) of the lines (with increasing costs for more capacity). Under the sensitivity, the resource is constructed, showing that this DC backbone is indeed a valuable resource, however the full potential capacity of the resource is not built. Instead, approximately 600 MW of the Century to Victorville-LA line is converted to DC (instead of the full 1,700 MW of potential capacity), and a combined 1.7 GW of the potential 7.5 GW of in-basin DC transmission is built. This suggests that this asset could be a useful component in the future system, but optimal size of the asset would require further analysis to determine. The cumulative through 2045 cost impact of this sensitivity is a *decrease* of ~9% compared to the core scenario.

Table 18. Transmission Investments for Each Investment Sensitivity

	SB 100	**Early/NoBio**	**Early/NoBio**	**Early/NoBio**	**Trans. Focus**	**Trans. Focus**	**Trans. Focus**
Location	High Core	High Core	High No In-basin Combustion	High Allow RE-CT	High Core	High No In-basin Combustion	High No Presc. Backbone
In Basin	232 MW 1 line 2.8 km	468 MW 3 lines 24.8 km	1,457 MW 8 lines 90 km	143 MW 3 lines 38 km	127 MW 1 line 2.8 km	1,402 MW 6 lines 75 km	126 MW 1 line 2.8 km
In-Basin DC					7,500 MW 3 lines 55 km	7,500 MW 3 lines 55 km	1,694 MW 3 lines 55 km
Out of Basin		2,354 MW 3 lines 379 km	2,032 MW 2 lines 107 km			163 MW 1 line 85 km	
Out to In Basin					1,700 MW 1 line 110 km	2,441 MW 2 lines 209 km	627 MW 1 line 110 km

3.3.5 Technology Costs

The final set of sensitivities we present explores the impacts of alternative assumptions about the future costs and performance of technologies on the technology pathways and their associated costs. Table 19 details the suite of technology cost sensitivities that were run across all LA100 core scenarios. The results from these sensitivities show that while the overall roles of wind, solar, diurnal storage, and firm capacity such as seasonal storage remain consistent across a wide range of technology cost assumptions, changes in the projected evolution of these technologies (e.g., due to R&D) can impact the ultimate balance of different technologies deployed and the associated costs of achieving the 100% target.

Table 19. Technology Cost Sensitivities

Core Scenario	Sensitivity Name	Sensitivity Definition
All scenarios	High Cost H_2	H_2 technology costs do not decrease after 2035
All scenarios	Low Cost H_2	H_2 technology costs are reduced to 80% of core scenario costs
All scenarios	High Battery Costs	Battery costs follow NREL's Annual Technology Baseline (ATB) high cost projections[42]
All scenarios	Low Battery Costs	Battery costs follow the ATB low cost projections
All scenarios	Low Offshore Wind Costs	Offshore wind costs follow ATB low cost projections
All scenarios	High Solar Costs	Solar costs follow the ATB high cost projections
All scenarios	Low Solar Costs	Solar costs follow the ATB low cost projections

For each of the sensitivities, Figure 48 shows the difference in capacity in 2045 relative to the associated core scenario. Positive values indicate more capacity in the sensitivity, and negative values indicate less capacity compared to the core scenario. Examining each cost sensitivity individually demonstrates that some sensitivities, in particular those associated with technologies used widely across scenarios (e.g., solar, batteries), show fairly consistent impacts across scenarios. For example, the Low Solar Cost sensitivity drives an increase in PV and PV + battery capacity across the full suite of scenarios, typically offsetting wind capacity. However, other sensitivities show substantial differences in the magnitude and composition of the technology across scenarios. For example, the High Cost H_2 sensitivity has a very large impact on the Early & No Biofuels scenario, driving a large reduction in H_2-CT deployment and an increase in a mix of PV + battery, storage, and geothermal, while the impact on Transmission Focus and Limited New Transmission scenarios is much less pronounced and there is no impact on SB100. Furthermore, with the high H_2-CT costs we see a substitution of the H_2-CT and onshore-wind capacity for solar and offshore-wind capacity. This offshore wind capacity is delivered directly into the city of LA through submarine cables, and it can satisfy a portion of the capacity needs that H_2-CTs had been in the core scenario. However, offshore wind cannot completely replace the need for in-basin capacity given the requirements to operate continually for multiple days.

[42] Cost projections for all technologies can be obtained at "Annual Technology Baseline ," NREL, https://atb.nrel.gov/.

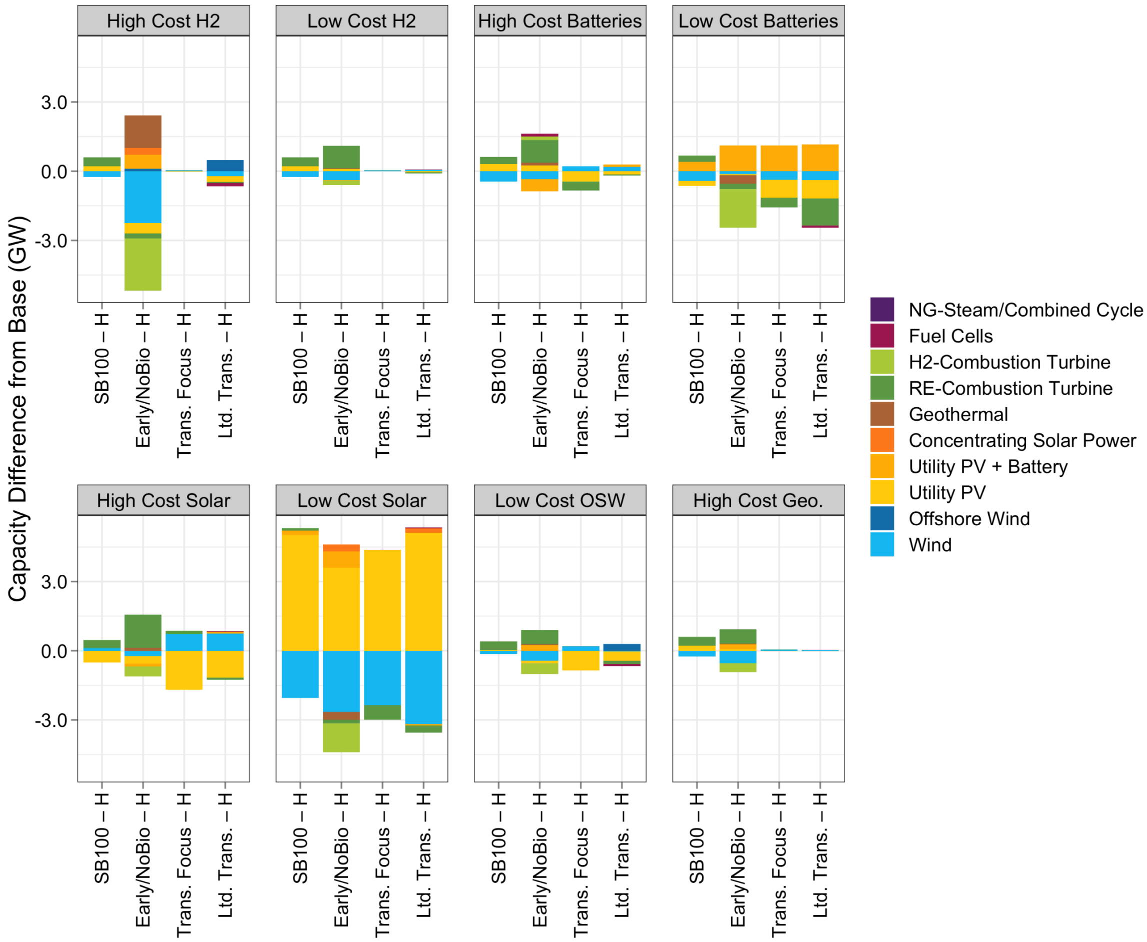

Figure 48. Capacity differences in 2045 for all technology cost sensitivities, High scenarios

Capacity above 0 GW on the y-axis represents an increase in capacity due to the cost changes compared to that scenario's base case; capacity below 0 GW represents reductions in capacity.

Figure 49 shows the cumulative costs associated with each core (base) LA100 scenario and associated sensitivities. The variation in the total cumulative costs across sensitivities in 2045 shows that the costs associated with transitioning to a 100% renewable or clean system can be substantially impacted by the evolution of technologies, particularly those that play key roles throughout the transition. As an example, more rapid cost declines in solar technologies alone could reduce the cumulative costs of compliance by 9% to 14%, depending on the scenario.

As LADWP pursues the 100% renewable energy transition, maintaining flexibility to pursue alternative technology deployment (as some technologies improvements are realized and others are not) will help achieve the 100% target and associated goals.

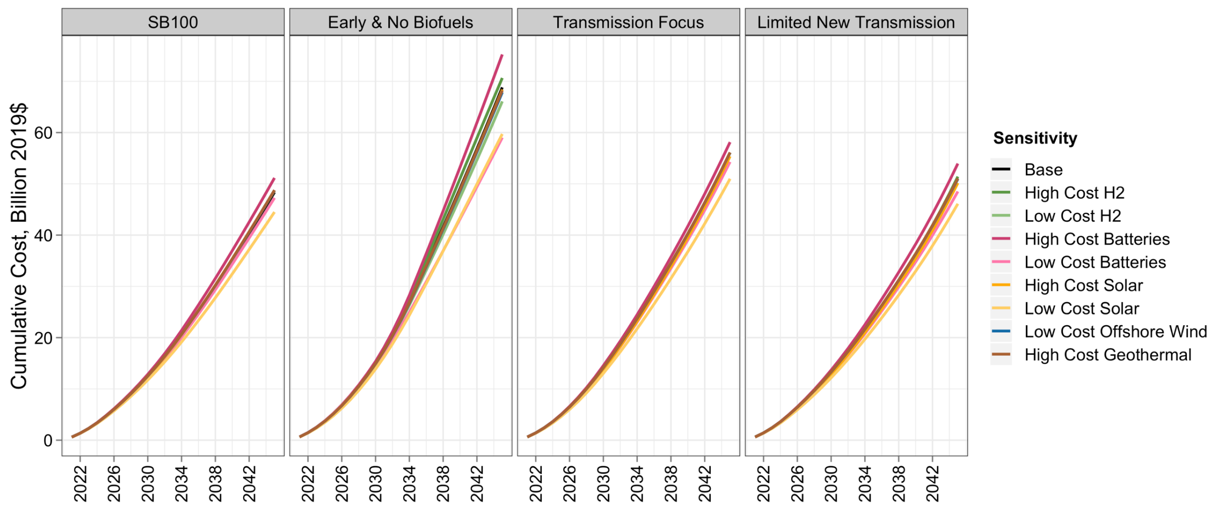

Figure 49. Cumulative cost by year across the base (core) scenarios and sensitivities

4 How Do We Keep the Lights On?

To ensure reliable operation, several modeling steps were performed in two general categories. The first is ensuring the system can operate on a day-to-day basis, under the "new normal" of relying on largely weather-dependent resources, as discussed in Section 4.1. The second is ensuring the system is robust to outages of generators and transmission, as discussed in Section 4.2.

4.1 Day-to-Day Operations

Verifying the ability of the LADWP system to remain reliable under normal operating conditions consists of first ensuring that the supply of energy from LADWP's generation fleet matches the demand for electricity across multiple time scales from days to seconds. This analysis is performed with the PLEXOS production cost model and discussed in Sections 4.1.1 through 4.1.3. After this analysis, we verify that the transmission system can operate under "steady state" conditions, which means that the wires, transformers and other elements of the transmission network are not overloaded, even during periods of high demand. This analysis is performed with the PSLF power flow model and discussed in Section 4.1.4.

4.1.1 Balancing

The primary goal of PCM analysis with PLEXOS in the LA100 study is to ensure that 1) the system envisioned in RPM can balance load in every hour of the year and 2) confirm that the dispatch results in 100% renewable energy by the target date.

All modeled scenarios can achieve 100% renewable energy while maintaining balance of supply and demand with no unserved energy during normal operations. Load balancing in 100% renewable scenarios is achieved via a combination of renewable resources including variable renewables, storage, and a mix of dispatchable resources.

Figure 15 and Figure 16 in Section 2.1 show the annual mix of generation in each scenario. For all LA100 scenarios, by the year 2030 and beyond we see generation mixes that are dominated by variable renewable resources. As a result, diurnal energy storage (with less than 12 hours of capacity) and responsive demand are often used to balance supply and demand, as well as provide operating reserves, as discussed in Section 2.4. The LA100 scenarios consider the deployment of many types of storage: standalone battery storage, PV + battery storage, pumped hydro storage, and concentrating solar power (CSP) with energy storage.

While these combinations of resources can provide the majority of LA's energy needs, the scenarios also identify the role of firm capacity, ranging from the continued use of gas in the SB100 scenarios, to renewably fueled generators including long-duration storage in the form of renewably produced fuels such as hydrogen, as discussed in Section 2.6.

As an example, Figure 50 shows the dispatch for the SB100 – High scenario in 2030. It includes four different days of the year: one in the winter with moderate load, one in the spring with low load, one in the late summer with high load, and another moderate load day in the fall. These results are from the hourly PCM simulations. The objective function of the model is to minimize overall system variable costs under a large set of constraints including supply-demand balance, operating reserves, transmission limits and generator constraints. Capital costs are not part of the dispatch decision.

The plots display three load lines. The thin solid load line represents the *original*, or *native*, load. Two resources (demand response [DR] and storage) can substantially change the shape of the load. The dashed line indicates how DR can shift load around in time but keeps the total MWh or GWh load the same on an annual basis.[43] And finally, the *thick solid* line shows the fully shifted load profile, which includes native load with DR and storage charging. The *thick solid* line is, thus, the total load that generation must actually meet. The SB100 – High scenario achieves an annual renewable energy contribution of 78% in 2030, but still relies heavily on the gas fleet for providing reliable electricity during periods of peak demand or low renewable output. While battery and pumped hydro storage (PHES) are making a significant contribution, we also see gas generation during the shoulder hours before sunrise and after sunset. Overall, the contribution of gas during many hours is relatively high, and the gas fleet operates with an overall capacity factor in 2030 of about 34% (22% for natural-gas CTs and 40% for natural-gas combined-cycle plants). The system still relies heavily on the gas generation fleet to provide reliable service during periods of peak demand, or periods of significant transmission congestion.

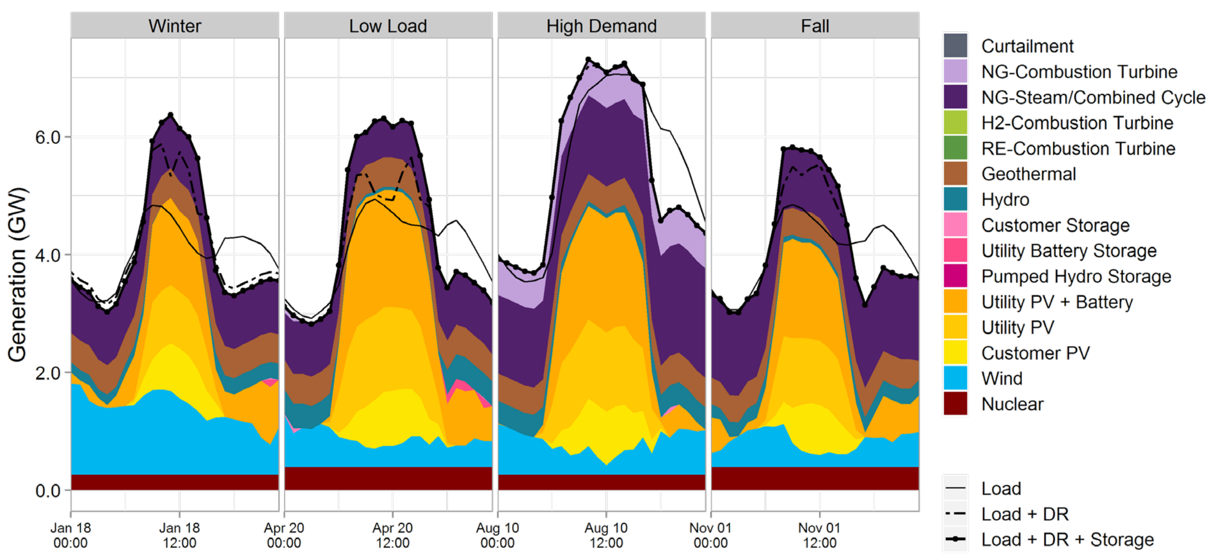

Figure 50. Hourly generation dispatch for four days in the SB100 – Stress 2030 scenario

Figure 51 shows four days in the Early & No Biofuels – High scenario in 2045, portraying the dispatch in an LA system without gas generation. This scenario relies heavily on diurnal storage to operate reliably, also utilizing dispatchable capacity in the form of hydrogen-fueled combustion turbines (H_2-CTs) to help serve load in the evenings and mornings. As discussed in Section 2.6, H_2-CTs turbines can use previously curtailed energy from other times of the year to create hydrogen that is stored and used during periods of higher demand, lower variable generation output, or transmission congestion. The *low load day* illustrates a sunny spring day

[43] Much of the shifted demand represented in the demand response profiles comes from flexible electric vehicle demand.

with relatively low load and lots of solar and wind output. On this day, the excess solar generation in the middle of the day is used to charge short-duration storage, which includes customer-sited batteries and pumped hydro energy storage (PHES) at Castaic. In the evening after sunset, the stored energy is dispatched to serve load, along with substantial contribution from wind and geothermal energy. This day does not require dispatching any seasonal storage (in the form of H_2-CTs or RE-CTs) due to the surplus of wind and solar energy. In fact, extra generation is being consumed to store energy during other periods of the year, such as the high demand day in August (which corresponds with low wind output). The *winter day* dispatch shows a period of simultaneous curtailment and in-basin H_2-CT generation at Scattergood and Harbor when there is insufficient transmission capacity on the Intermountain DC line to deliver wind resources received at Intermountain.[44]

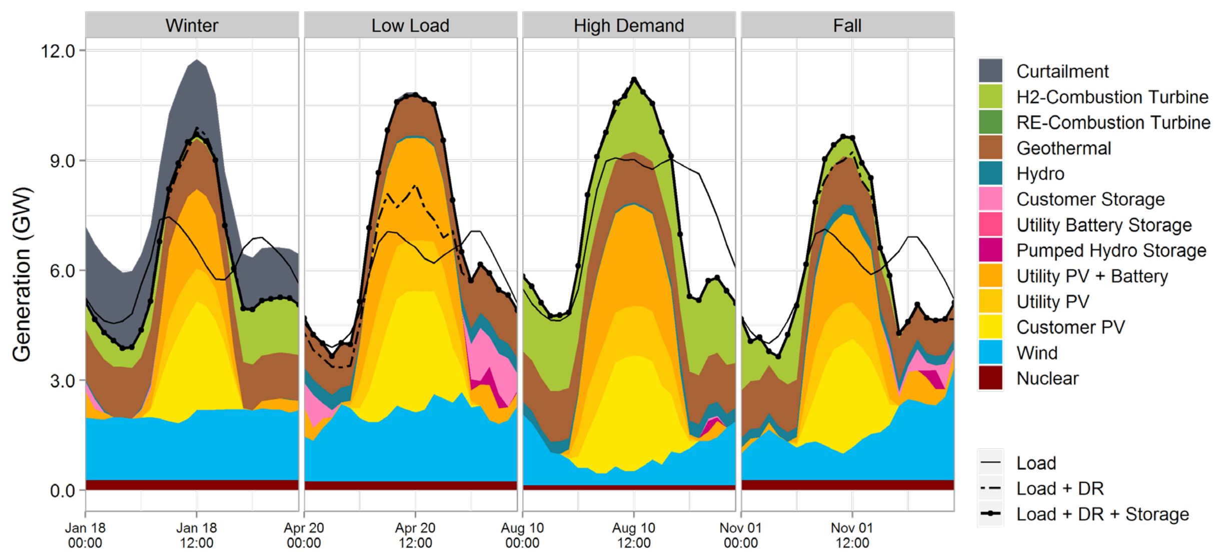

Figure 51. Hourly generator dispatch for four example days in the Early & No Biofuels – High 2045 scenario

At certain times of the year, many days of cloudy or low wind days may occur in a row. Figure 52 provides the dispatch for four consecutive days (November 15–18) from the Early & No Biofuels – High scenario in 2045. This plot shows days of low variable generation availability (November 15 is a low wind day and November 16 is a particularly low solar day). On those occasions, shorter-duration storage such as batteries and PHES are not sufficient to meet energy needs as their energy stores grow depleted. After they discharge their energy, there is very little excess energy left to recharge them. On these days, long-duration storage in the form of H_2-CTs is critical to meet load for days on end. In this case, wind generation picks up on the fourth day (November 17), allowing the H_2-CTs to ramp down for part of the day.

[44] The Intermountain DC line in particular is often congested during high wind conditions.

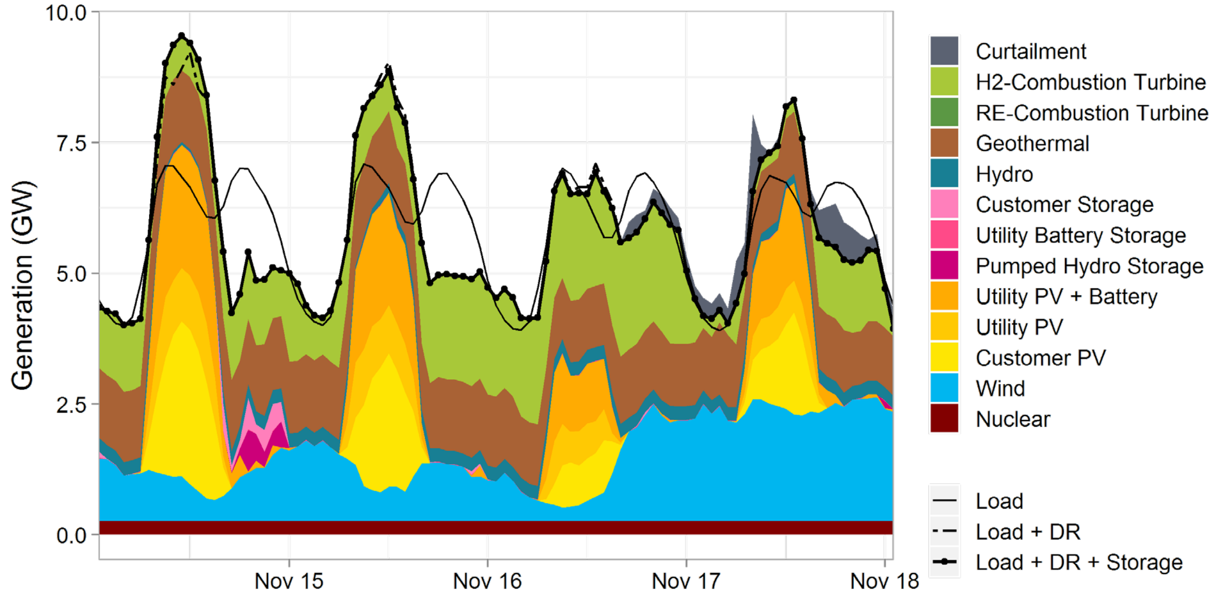

Figure 52. Hourly generation for low variable generation days in the Early & No Biofuels – High 2045 scenario

The overall importance of having diverse resources to balance supply and demand is illustrated in Figure 53. The figure shows duration curves for the hourly percentage of load served by two general classes of resources. Below the lines for each scenario is the fraction of load being met by variable generation (solar PV and wind) for all hours of the year in 2045 (sorted high to low). The 2020 scenario is also included as a reference. The space above the line is the fraction met by other generators, including geothermal, hydro, batteries, PHES, and combustion resources (natural gas in SB100, or stored renewable fuels in other scenarios). Figure 53 shows that during many hours of the year, most of LADWP's load is met by wind and PV. However, there are also more than 1,000 hours where these resources provide less than half of LADWP's demand, and other resources are needed to reliably serve load.

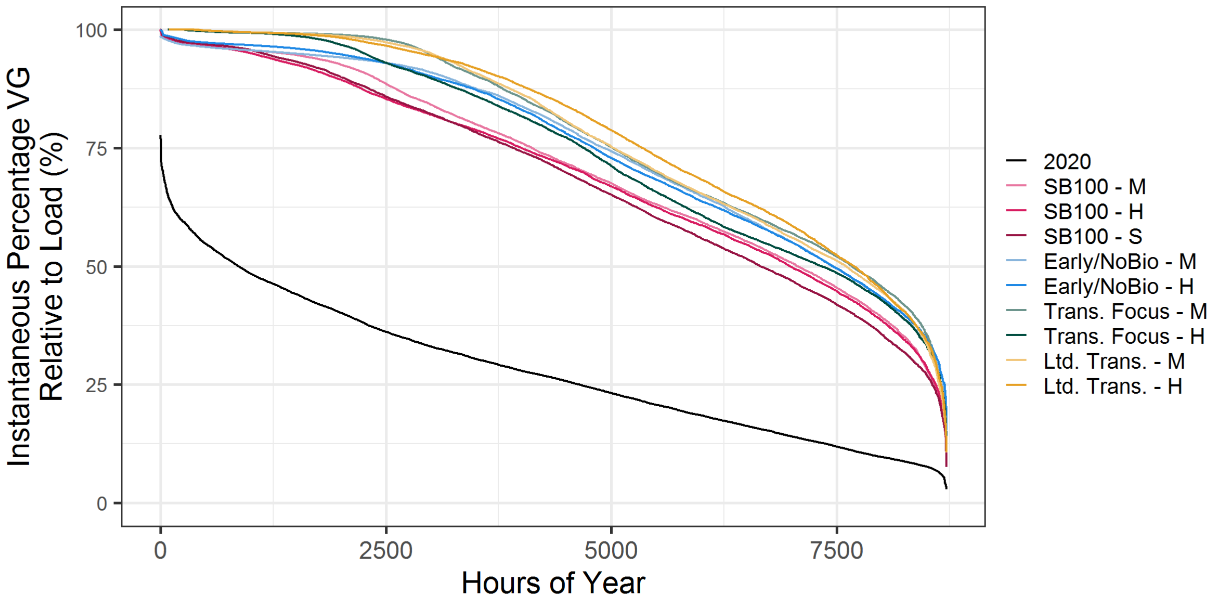

Figure 53. Hourly percentage of load being served by variable generation (PV and wind) for all scenarios in 2045

4.1.2 Ramping

The LA100 scenarios rely heavily on storage for balancing supply and demand, but also for ramping and providing operating reserves. In 100% renewable energy systems, there will be a significant increase in predictable net-load (demand minus the contribution from variable generation) ramp rates that occur from decreasing solar output during periods of high demand. As an example, Figure 54 shows the growth in three-hour ramp rate of net load for the year 2045 compared to the 2020 system. The maximum three-hour ramp in net load in the highest scenario in 2045 is over double the maximum ramp observed in the 2020 scenario.

Despite seeing higher levels of demand response (as well as storage deployment), which shifts total load to correspond better with available variable generation and reduces maximum ramping needs, LADWP will face somewhat higher maximum ramp rates if future load growth and demand response looks more like the High Load scenarios than the Moderate Load scenarios.

Across scenarios, maximum upward ramps are typically seen in the late afternoon or evening, when solar is ramping down and load is simultaneously ramping up. The scenarios with the highest amount of solar tend to face the highest net-load ramp, with the Early & No Biofuels – High scenario experiencing a ramp of almost 4,500 MW on a spring evening as the suns sets and wind resources do not ramp up until a few hours later. The SB100 – High Stress scenario has the second-highest three-hour ramp overall, just over 4,000 MW in three hours. Although the SB100 scenarios minimize ramping requirements by allowing for natural gas combustion, the high degree of electrification and relatively less load flexibility in the High Load Stress scenario means that such a future could result in substantial ramp rates.

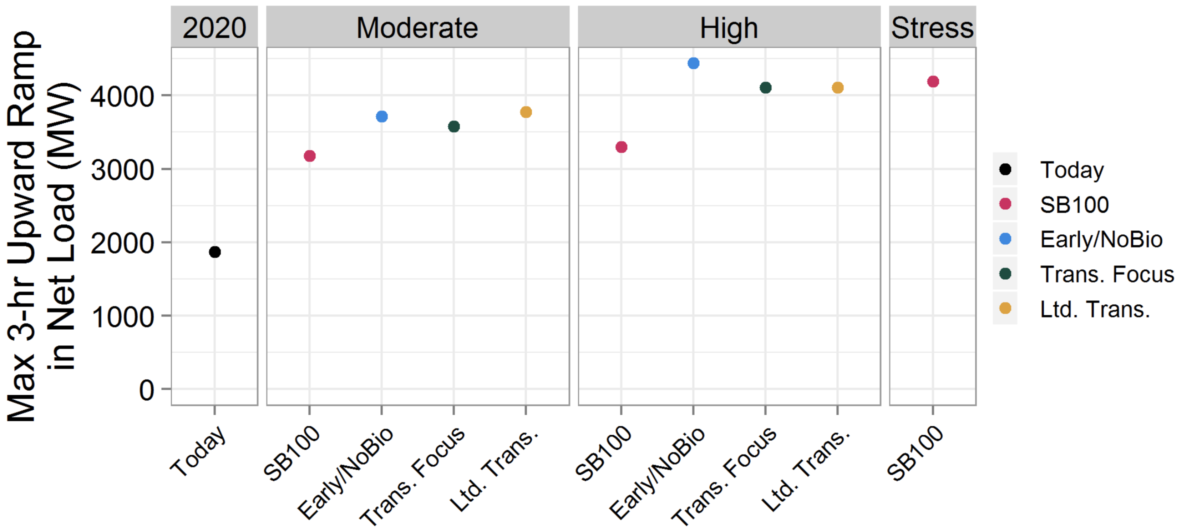

Figure 54. Maximum upward three-hour ramp in net load across the LADWP system for all scenarios in 2045

The largest maximum up-ramp event highlighted above, which occurs in the Early & No Biofuels – High scenario, takes place throughout the early evening of May 14, 2045 as solar ramps down (while load ramps *up*) and is shown in the orange box on the left side of Figure 55. Meeting the ramp requires the use of a variety of flexible resources. About a quarter of the ramping capacity comes from energy storage, with most of the rest from RE-CTs and H_2-CTs and geothermal, to a lesser degree. These assets provide LA with energy throughout the critical peak hours until wind resources across the West ramp upward later in the evening. Th evening transition in generation technologies shown here represents a case that is somewhat extreme in magnitude but typical of the operational strategy that LADWP is likely to undertake more frequently as the penetration of renewable energy increases across the system.

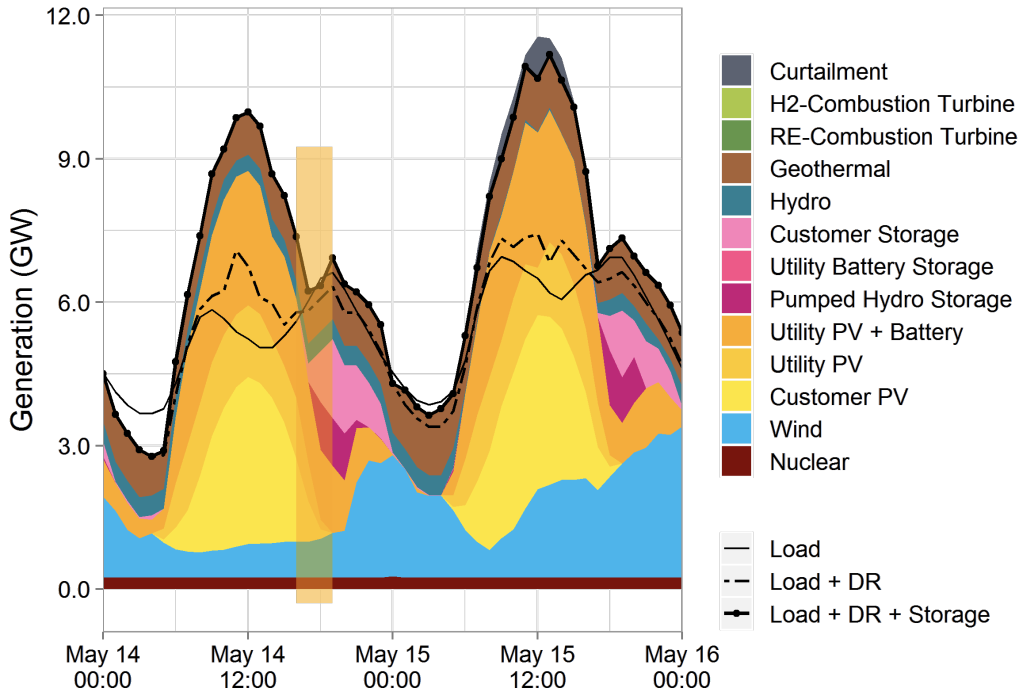

Figure 55. Dispatch of period with highest three-hour net-load ramps in the Early & No Biofuels – High scenario in 2045

4.1.3 Operating Reserves

LA100 simulations consider the co-optimized dispatch of generators for provision of both energy and operating reserves. Two general types of operating reserves are required: contingency reserves and reserves held to address un-forecasted subhourly variability. The first type addresses unplanned outages that can occur rapidly. The second type addresses normal variability of both resource supply and demand that occurs over timescales from multiple seconds to (more typically) minutes. Contingency reserves are typically sized to address the largest likely failure, which in the case of LADWP is driven by large transmission lines, such as the PDCI.

As the amount of variable generation on the system increases, there will likely be an increase in the amount of the second type of operating reserves required due to unpredictable subhourly variability ramping that occurs across various timescales. The LA100 study includes two types of reserve to address subhourly variability, differentiated by timescale. Very short (less than a few minutes) variability is addressed by regulating reserves. Un-forecasted variability on the timescale of a few minutes is addressed by a flexibility/ramping reserve product now being implemented in some ISOs/regions with large amounts of wind and solar deployment.[45,46]

Subhourly variations (primarily deviations from the hourly trends in net load ramps) are addressed via these reserves. We examine the subhourly variability of net load using 5-minute wind and solar data and estimate the un-forecasted deviations from the hourly ramps.[47] These deviations are measured, and sufficient operating reserves to address these deviations are required in the simulations. By ensuring that sufficient operating reserves are available, subhourly variability can be addressed, without actually performing simulations on a minute-to-minute time scale. An exception is the impact of very short-term events such as contingencies, which does require more detailed modeling and is discussed in detail in later sections.

Reserves can be provided by generators with spare capacity to increase output over the needed timescale. In systems with high amounts of zero-marginal-cost generators (such as wind and solar), it can also lead to *over-procurement* of reserves products. An optimization model such as PCM sees a free source of downward reserves (up to the amount that the generator is currently providing) or upward reserves (up to the amount that the generator is already being curtailed).[11] While over-procurement of reserves is not an inherent problem, it can make trends in reserve procurement hard to report, or obscure potential shortage of reserves at other times.

Figure 56 illustrates the annual reserve provision broken down by generator type for the year 2030 as an example. The plot includes both upward reserves (here including spinning contingency, regulation, and flexibility) and downward reserves (regulation and flexibility).[12] The annual requirement for upward reserves (varying hourly based on load and variable generation availability) is around 12 TW-h (units represent capacity held for a period of time) in 2030, but varies by scenario.[13] Although the total reserve requirement is shown both on the "In Basin" and "Out of Basin" portions of the plot, the reserve requirement is around 12 TW-h *total* from either in- or out-of-basin generators—there is no separate requirement for in-basin generators versus out-of-basin generators. Over half of the reserve requirement is coming from in-basin, largely Castaic PHES and in-basin natural-gas generators. A significant portion of reserves is served outside of the basin, mostly by renewable generators, including curtailed wind and solar.

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[45] Erik Ela, Michael Milligan, and Brendan Kirby, "*Operating Reserves and Variable Generation: A Comprehensive Review of Current Strategies, Studies, and Fundamental Research on the Impact that Increased Penetration of Variable Renewable Generation Has on Power System Operating Reserves"* (NREL 2011) NREL/TP-5500-51978 https://www.nrel.gov/docs/fy11osti/51978.pdf.

[46] E. Ibanez, I. Krad, and E. Ela, *A Systematic Comparison of Operating Reserve Methodologies*, Preprint, To be presented at the IEEE Power and Energy Society General Meeting, National Harbor, Maryland, July 27–31, 2014 (NREL 2014), NREL/CP-5D00-61016, https://www.nrel.gov/docs/fy14osti/61016.pdf.

[47] Marissa Hummon, Paul Denholm, Jennie Jorgenson, David Palchak, Brendan Kirby, and Ookie Ma, *Fundamental Drivers of the Cost and Price of Operating Reserves* (NREL 2013), NREL/TP-6A20-58491, https://www.nrel.gov/docs/fy13osti/58491.pdf.

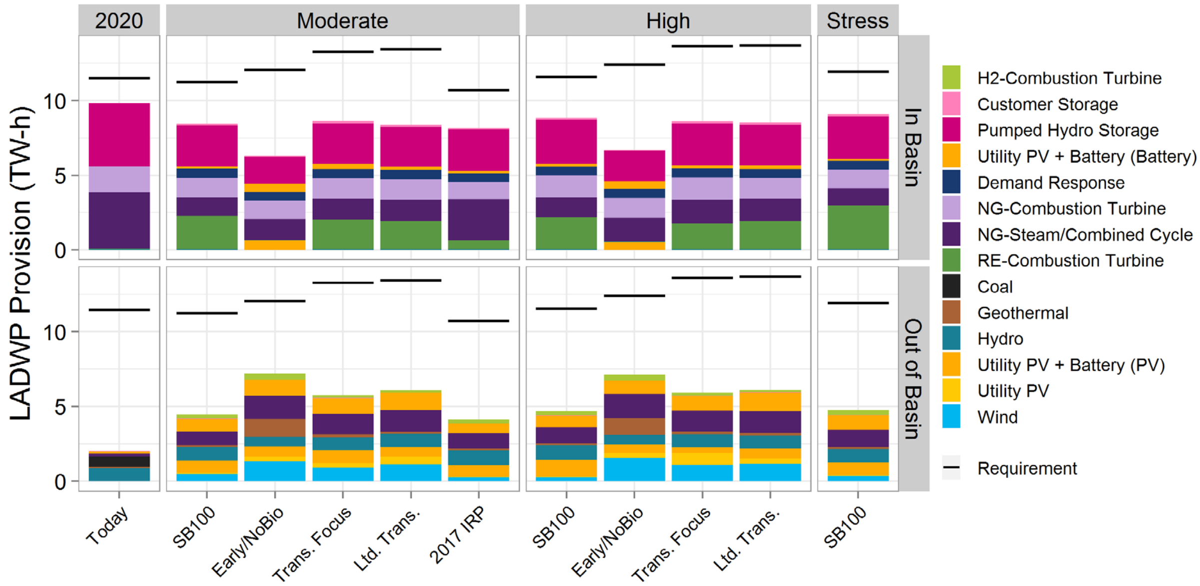

Figure 56. Annual reserve provision for all scenarios in 2030, broken down by physical location of the providing generator (in-basin or out-of-basin)

LA100 allows out-of-basin resources to provide certain longer-duration reserve produces like flexibility and non-spinning contingency reserves. However, because reserve *deployment* is not considered, contingencies could limit the actual deliverability of energy, and out-of-basin resources might not be able to provide their reserve requirement if called upon. PCMs do provide ways to address this shortcoming (such as a constraint that would examine transmission flows in every hour, or a constraint to limit the amount of reserves being provided by out-of-basin resources). We found the computational burden of enforcing power flow constraints under multiple contingency scenarios for all hours of the year computationally intractable. Instead, we require that all contingency reserves must be provided by some combination of 1) in-basin resources with sufficient headroom, 2) Castaic PHES, and 3) out-of-basin PV + battery hybrid plants, which are spatially diverse. We assumed Castaic can provide spinning reserves while operating in condensing mode, given its rapid response rate. Figure 57 shows the contingency portion of the reserve requirement for 2030, separated into spinning and non-spinning components. Non-spinning contingency is less binding, as it does not require the generators to already be online, and as a result is provided by natural-gas-fired generators, and either RE-CTs or geothermal, depending on the scenario.

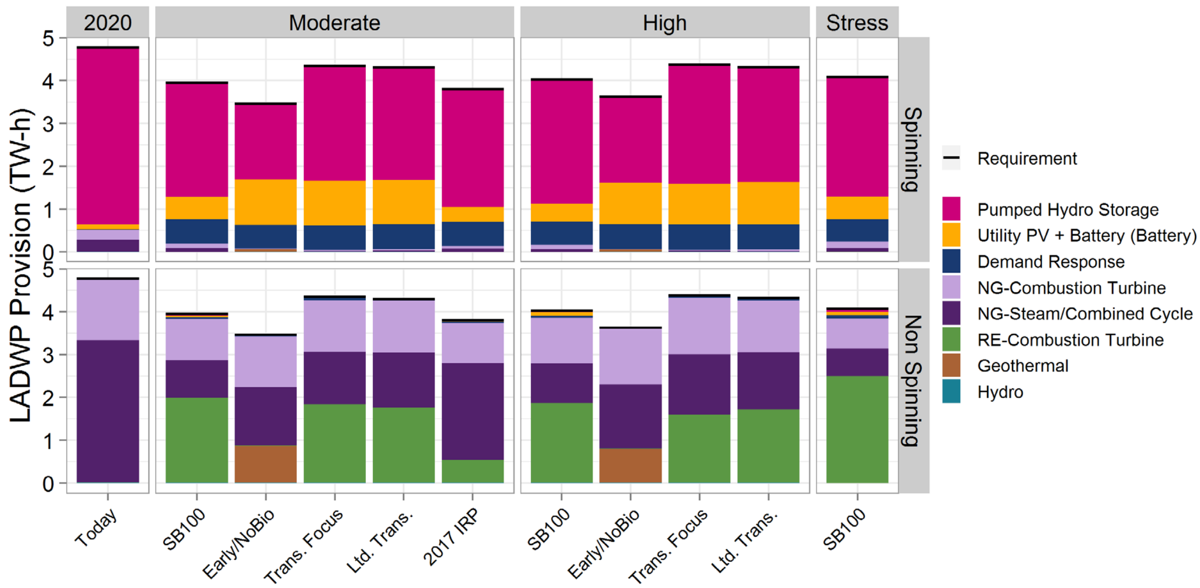

Figure 57. Annual reserve provision for spinning and non-spinning contingency reserve for all scenarios in 2030

Figure 58 shows the resource mix that provides reserves in 2045 for all scenarios. Compared to 2030 we see much less provision from natural-gas generators, as most scenarios do not allow any by 2045. RE-CTs and DR provide an increasing amount of reserves, as do out-of-basin resources such as wind. Figure 59 shows the mix for only contingency reserves, again showing much of the spinning portion provided by Castaic PHES, with the bulk of non-spinning portion coming from RE-CTs or H_2 fuel cells, depending on the scenario.

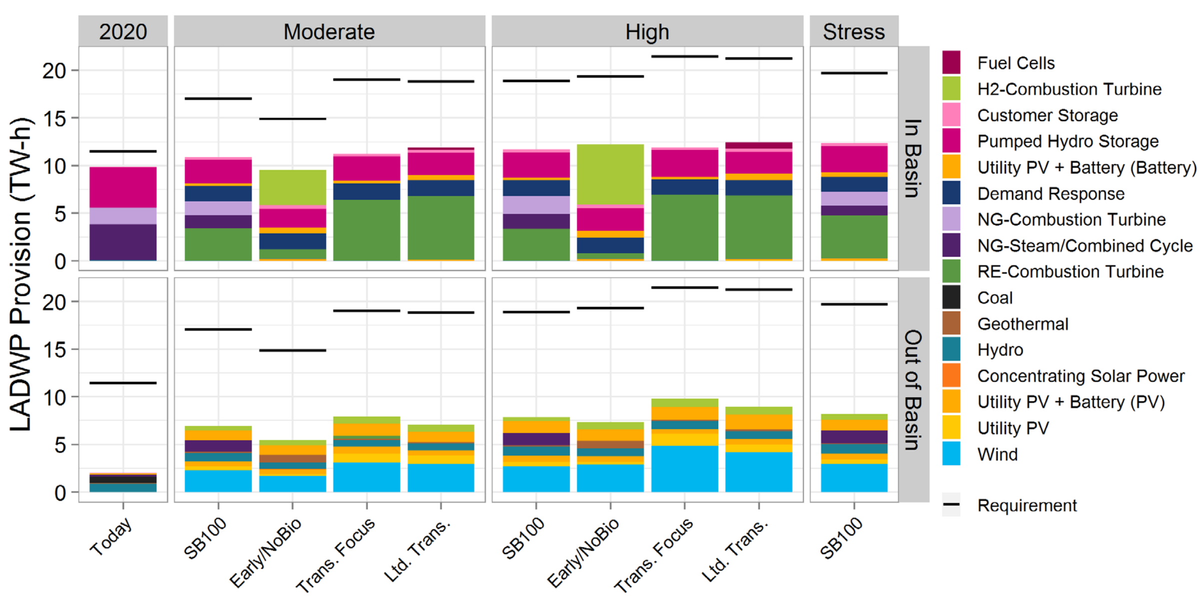

Figure 58. Annual reserve provision for all scenarios in 2045, broken down by physical location of the providing generator (in-basin or out-of-basin)

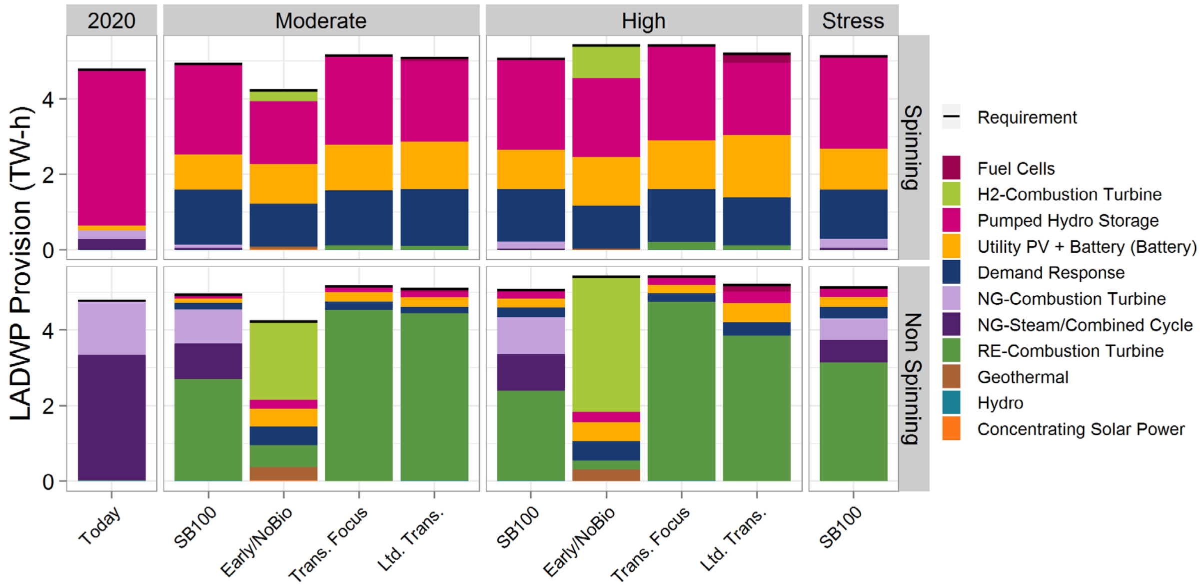

Figure 59. Annual reserve provision for spinning and non-spinning contingency reserve for all scenarios in 2045

As mentioned above, PCMs such as PLEXOS consider *provision* of operating reserves, but not their actual *deployment.* This leads to complications with storage, particularly as in our results the PCM uses storage to fulfill much of its reserve requirement. In fact, in many hours in certain scenarios, over 75% of the upward reserve requirement may be coming from energy storage, which includes Castaic PHES, PV + battery generation, and standalone batteries (see Figure 60 as an example for all scenarios in 2030). Because PLEXOS is co-optimizing the cost of providing energy and ancillary services, it will optimally choose the lowest-cost method to provide reserves. Storage, with low or no variable costs, often has spare capacity to provide reserves. This is lower cost than providing reserves from part-loaded thermal generators, which have non-zero variable costs and have minimum generation levels that decrease their flexibility compared to battery storage. This represents an important and fundamental change in how a power system provides operating reserves.

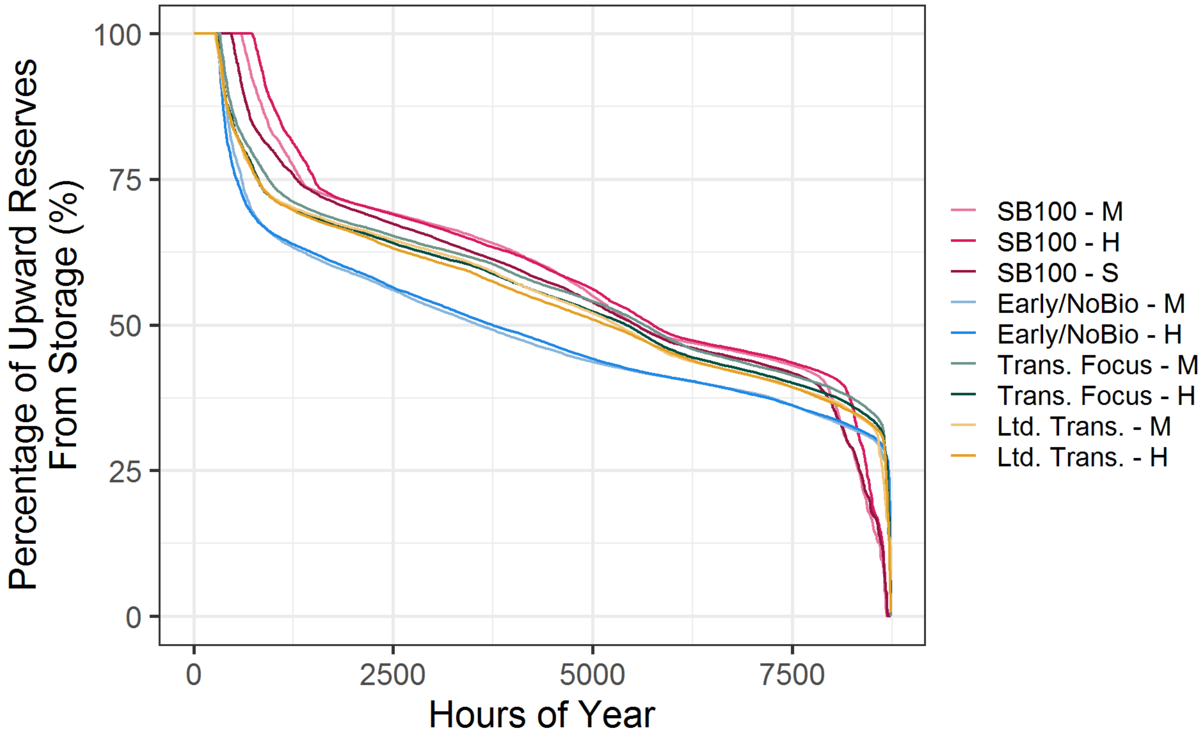

Figure 60. Percentage of hourly upward reserves provided by storage (sorted high to low) in all 2030 scenarios

While contingency reserves may seldomly be needed, a lack of stored energy may make it impossible to fulfill the required response, depending on the time needed to call non-spinning/replacement reserves. We require a 30-minute duration for storage providing spinning reserves, after which non-spinning units must respond. In LA100, all the existing longer-start-time gas units are eventually replaced with a variety of resources including RE- or H_2-CTs. This allows for a more rapid response, but there may be other complicating factors such as the time to start complicated fuel-supply resources such as ammonia cracking facilities for H_2 turbines. The impact of extended outages on the ability to recharge batteries and maintain operating reserves is considered in Section 4.2.2.

The use of both variable generation downward dispatch and battery storage with less energy capacity compared to Castaic requires careful analysis of the storage durations required to maintain reliability during the planning process. It also will require careful monitoring of storage state of charge and optimal dispatch to achieve high renewable energy targets, minimize cost, and maintain reliability.

We monitor the amount of reserves held in each hour to ensure the system can respond to short-term contingency events and un-forecasted variations in net load. There is also only a small number of hours with reserve violations in any of our simulations, with the highest occurring in the SB100 – High scenario, which has the highest magnitude of reserve shortages (1 hour with

160 MW-h of shortfall). This amount is too small[48] to make a statistically significant identification of the cause, given the random nature of outages that occur in the simulation.

This analysis does not include other operational impacts that occur at short timescales, such as the dynamic performance of the power system. For this study, the energy setpoints determined in PCM are sent to a load flow software (PSLF), where a base power flow and a transient and post-transient stability analysis is executed on a large number of predefined contingency scenarios in order to verify the AC feasibility and stability of the power system design outside regular operating conditions for a small number of scenarios and snapshots in time. That is the subject of the next section (Section 4.1.4). For further reading, previous studies have also begun to assess frequency stability concerns at high renewable penetrations.[49,50,51] While we assume deployment of synchronous condensers to assist in providing frequency support services (including inertia) inverter-based resources are increasingly used to provide these services as well.

4.1.4 Steady-State Contingency Analysis Results from PSLF: How Many Transmission Lines Need to Be Upgraded/Built?

The initial power flow analysis considered steady-state, pre-contingency conditions where the power system is operating under essentially normal conditions. However, these conditions were also chosen to represent periods where the transmission system may be stressed. These normal conditions were then evaluated under contingency conditions as discussed in Section 4.2.3.

As detailed in Appendix E, for the 2030 SB100 – High Load Stress and 2045 Early & No Biofuels – High Load scenarios, four power flow cases were prepared:

1. **Base Case**: Replica of the RPM/PLEXOS load, generation, and transmission in PSLF as per the methodology discussed in Appendix D and Appendix E.
2. **Monsoon Sensitivity**: Same as base case but with no solar generation in the entire LADWP balancing authority because of monsoon conditions.
3. **High Northern Imports Sensitivity**: Same as base case but increased imports from LADWP resources in the North.
4. **VIC-LA Sensitivity**: Same as base case but increased imports over the VIC-LA path.

Import directions for the high northern imports and VIC-LA sensitivities are shown in Figure 61.

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[48] About 65 parts per million.

[49] N.W. Miller, M. Shao, S. Pajic, and R. D'Aquila, *Western Wind and Solar Integration Study Phase 3: Frequency Response and Transient Stability* (NREL 2014), NREL/SR-5D00-62906. http://www.nrel.gov/docs/fy15osti/62906.pdf.

[50] Nicholas W. Miller, Miaolei Shao, and Sundar Venkataraman, *California ISO (CAISO) Frequency Response Study: Final Draft* (GE Energy, 2011), http://www.caiso.com/Documents/Report-FrequencyResponseStudy.pdf.

[51] N.W. Miller, *Low Carbon Grid Study: Discussion of Dynamic Performance Limitations in WECC* (2015).

Figure 61. Import locations for northern imports and VIC-LA sensitivities

A summary of pre-contingency load, generation, distributed generation, and Pacific DC Intertie and Southern Transmission System (STS) DC lines flows in Area 26 or the LADWP balancing authority in the eight cases is shown in Table 20. Load is measured on the low voltage side of transformers and includes all the LADWP balancing authority obligations, including Glendale and Burbank.

Table 20. Summary of Real Power Generation and Demand in LADWP in the 2030 and 2045 Power Flow Cases

Scenario	Case	Load Power (MW)	Bulk Generation (Total/LA Basin; MW)	Distributed Generation Net Power (MW)	PDCI Power (MW)	STS Power (MW)	Imports Power (MW; includes PDCI)	Power Losses (MW)
2030 SB100 – Stress	Base	7339	7410/2317	-741	31	1160	860	190
	Monsoon	7339	7639/4194 (including 1250 from Castaic)	-1009	31	1160	867	158
	Northern Imports	7339	5956/1612 (including 1250 from Castaic)	-741	1605	0	2607	483
	VIC-LA	7339	6659/801	-741	31	2077	1746	326

Scenario	Case	Load Power (MW)	Bulk Generation (Total/LA Basin; MW)	Distributed Generation Net Power (MW)	PDCI Power (MW)	STS Power (MW)	Imports Power (MW; includes PDCI)	Power Losses (MW)
2045 Early & No Biofuels – High	Base	8340	7547/2022	-619	78	1428	1717	305
	Monsoon	8340	7659/3844 (including 1250 from Castaic)	-564	78	1428	1485	241
	Northern Imports	8286	6124/2032 (including 1250 from Castaic)	-619	1605	0	3316	535
	VIC-LA	8340	7546/1793	-619	78	1656	1743	330

The Base Case shows the substantial increase in imports due to the increased load of 1,000 MW from 2030 to 2045, as well as the increase in power losses, with additional details provided in Appendix E. The Base Case occurs during a period of relatively low distributed PV output, and combined with significant in-basin charging of batteries, there is a net negative generation from in-basin distributed resources. Key differences in the sensitivity cases include:

- **Monsoon** – In both 2030 and 2045, imports have either stayed almost the same or reduced compared to the base cases. Because the loss of solar power was compensated by increasing battery storage and in-basin firm capacity resources that were predominantly within the LA Basin, the losses reduced compared to the corresponding base cases.
- **High Northern Imports** – Substantial reduction in generation in LA Basin generation primarily compensated by imports over the PDCI, increase in Castaic generation, and higher flow from Northern generators resulting in high imports and significantly higher losses in both 2030 and 2045 compared to the base cases.
- **VIC-LA** – Increased VIC-LA flow to 4,300 MW. In 2030 this produces a significant increase in Intermountain DC flow, and imports from Arizona, with corresponding reduction in LA Basin generation. This resulted in increased losses compared to the base case. In 2045, however, VIC-LA flow was already close to 4,100 MW, so there is only a small increase in STS flow and small increase in losses compared to the base cases.

The 2030 cases found no pre-contingency thermal violations. The 2045 cases found five overloads (three lines and two transformers), but these repeat in post-contingency violations as well.

4.2 Planning for Extreme Events and Contingencies

In addition to operations under normal conditions, the LA100 study evaluated the impact of unusual weather conditions and outages. Section 4.2.1 first explores the impact of normal outages and weather variations, to identify possible conditions where much lower availability of wind and solar could impact resource adequacy. Section 4.2.2 considers the impact of extended outages on the transmission system, where the supply of out-of-basin resources might be disrupted for weeks or longer. Finally, Section 4.2.3 evaluates the impact of contingency events, when an unexpected failure of a transmission line or generator requires the system to rebalance, potentially causing overloads on the remaining parts of the transmission system.

4.2.1 Sufficiency of Supply to Meet Demand all Times of the Year (Resource Adequacy) and Under Different Weather Years

We used NREL's Probabilistic Resource Adequacy Suite (PRAS) to analyze 100,000 random hourly draws of generator and transmission outages for each of 7 weather years. Aggregated generator dispatch, storage charging and discharging, and interregional load balancing (in a transport model representation) are modeled in a chronological hourly simulation under varying randomly sampled generator outage conditions, based on unit-level mean time-to-failure and mean time-to-repair parameters. In addition to generator outage conditions, we also evaluated transmission outages, assuming the transmission links are randomly unavailable for an average of 3 weeks per year (5.8% forced outage rate).[52] We use the commonly used threshold for loss-of-load expectation (LOLE) of 1 day in 10 years, interpreted hourly as 2.4 hours/year.

For the year 2045, we observe that the LOLE for all nine scenarios is well below the threshold, which is shown in Figure 62. The lines of Figure 62 indicate how the LOLE changes with the addition or subtraction of firm capacity. The points at zero on the x-axis thus illustrate the estimated LOLE for each scenario, assuming no capacity adjustments. The figure shows all scenarios will remain below the target reliability threshold for LOLE, even after removing 2 GW of firm capacity. Overall, these 2045 results show that the base systems meet the resource adequacy criteria we impose here, and the limits to reliability are driven primarily by transmission outages that could limit delivery of energy to specific locations in the LA Basin.

[52] Outages include simultaneous combinations of multiple components (including multiple transmission elements, generators or both). Outages represented should be interpreted as short-duration outages of generators or transmission lines, which last several hours to, at most, a few days. The implications of long-duration outages of transmission lines associated with natural disaster (e.g., fires) or other causes are evaluated using other methods, specifically unit commitment and dispatch simulations (using PLEXOS) of scenarios with year-long outages of key assets, as discussed in following sections.

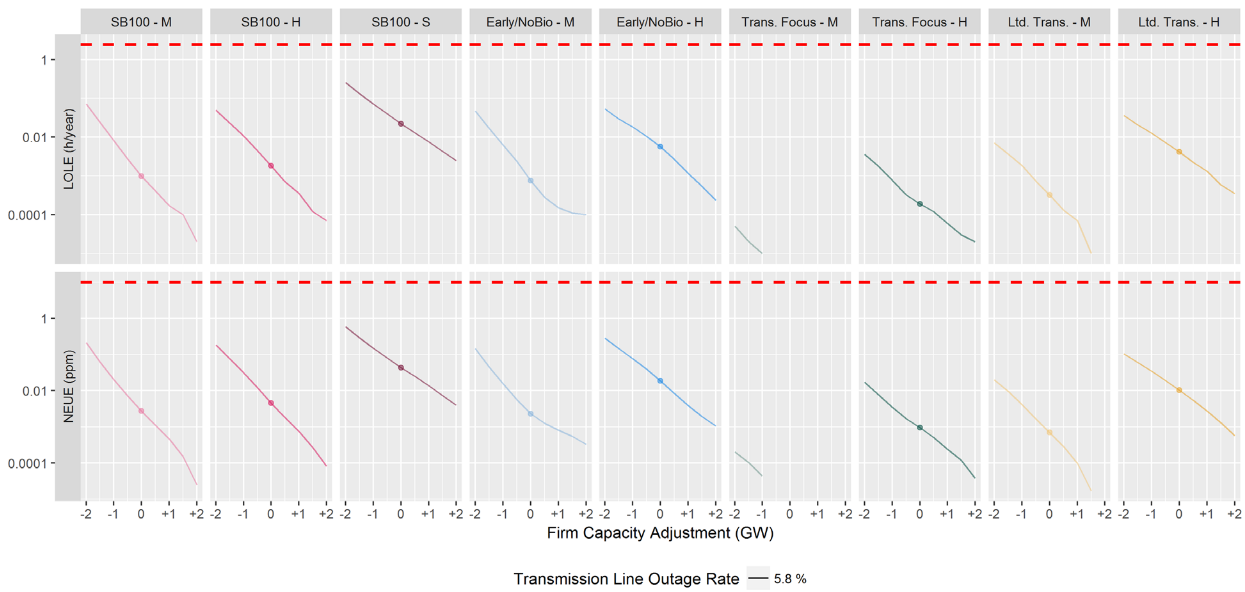


Figure 62. Resource adequacy metrics for 2045 for the nine LA100 scenarios

While Figure 62 only depicts a single weather year (2012), we evaluated earlier results using PRAS with a total of 7 weather years (2007–2013). Figure 63 shows the same resource adequacy metrics, but for all seven weather years on these earlier runs. The dashed lines indicate runs which include a 5.8% forced outage rate for transmission lines, whereas the solid lines have a 0% transmission outage rate. First, we can see that the resource adequacy metrics for a system with no capacity adjustments (at x = 0) fall under the adequacy threshold, even when considering the variation imposed by additional weather years. More importantly, however, the variation that is shown in the solid lines (transmission outage rate = 0%) disappears for the dashed lines (transmission outage rate = 5.8%), meaning there is very little variation across weather years. This indicates that the impact of reduced transmission far outweighs the impact of the weather year, which is why we include a non-zero transmission outage rate in our final calculation of resource adequacy metrics (Figure 62).

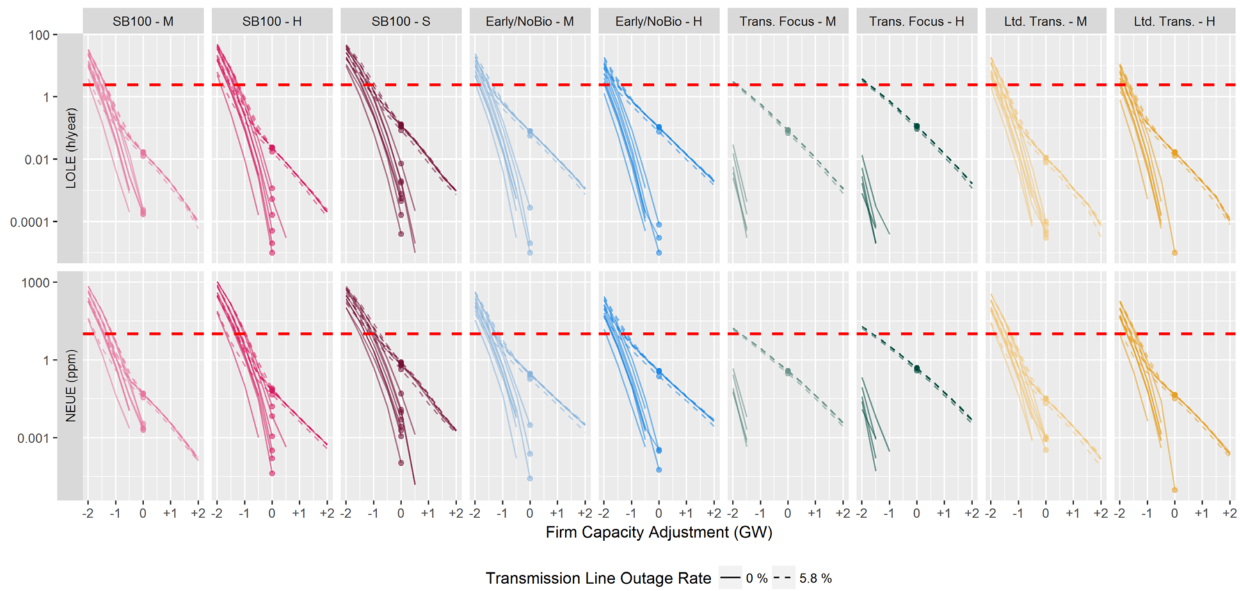


Figure 63. Resource adequacy metrics for 2030 for nine scenarios using an earlier set of results

Each line—solid or dashed—represents a different weather year. The solid lines represent 0% forced outage rates for transmission lines between the considered regions, while the dashed lines represent a 5.8% forced outage rate.

The PRAS results tend to indicate an overbuilt system examining only standard resource adequacy targets. However, the PRAS analysis does not consider long-duration outages that could last months. Thus, this additional capacity may be necessary to mitigate such outages.

4.2.2 Extended Transmission and Generator Outages

Because the power systems envisioned in the LA100 study rely heavily on transmission to access high-quality renewable resources, it is important to consider the possibility of extended transmission outages. Today, LADWP has several gigawatts of in-basin natural-gas-powered resources that can come online in the event of a transmission outage of any duration. Whether maintenance takes an in-basin line out of service for several months, or a wildfire forces one or more circuits offline on the path north to Haskell Canyon Switching Station, LADWP can utilize this natural gas capacity to serve demand. In a future without this in-basin natural-gas-powered capacity, a question arises as to where the ability to serve in-basin demand will come from in the event of a significant contingency that renders one or more transmission or generation assets unusable for days, weeks, or months.

A significant concern in the LA100 study scenarios is the ability to recharge energy storage resources during an extended outage of a major transmission component that reduces the ability to access out-of-basin renewable resources. The conventional reliability assessment methods used by system planners today chiefly consist of load flow studies like the analysis described in Sections 4.1.4 and 4.2.3, which offer a detailed electrical representation of the system at the expense of analyzing only one or a few isolated points in time. This presents a concern when analyzing systems with high penetrations of variable renewable energy accessible via limited transmission paths, since such methods give no insight into the system's ability to replenish storage resources during extended outages and assume that several points in time can be chosen to comprehensively represent the system under stress.

To evaluate the ability of the system to provide reliable service under extended outages, we use PCM to assess as a full, year-long outage each of 213 LADWP-provided contingencies plus several contingency events created by NREL.[53] While it is highly unlikely that any outage evaluated here would last for an entire year, outages lasting weeks or even months are common, and therefore this conservative assumption allows us to evaluate the system across a variety of conditions. Employing simultaneous parallel simulations on high-performance computers makes this type of analysis possible.

We analyze the performance of the LADWP system under these conditions for one scenario in one year. To choose one worst-case scenario in which the power system is most likely to face reliability challenges, we relied on the PRAS results discussed above in addition to PCM results from modeling prior RPM buildouts throughout the course of the study. We chose to focus on 2045 and the Early & No Biofuels – High scenario. While reliable within PRAS, this scenario exhibits the lowest margin in the PRAS results amongst scenarios that do not include fossil generation (as shown in Figure 62) and it imports the most energy from outside the LA Basin on an annual basis.

PCM simulations of long-duration outages in the 2045 Early & No Biofuels – High scenario are carried out for all LADWP-defined N-1 and critical N-1-1 contingencies,[54] in addition to a range of more extreme cases provided by LADWP and still more cases designed by NREL to assess new risks that may come about as the system transitions to 100% renewable energy. This means that the outage cases assessed in the study range from relatively low-risk situations frequently encountered in day-to-day operations in which one generator, circuit, or transformer is taken out of service for a sustained period to certain extreme situations involving multiple outages of critical assets that LADWP is unlikely to encounter in a given year, but that may adversely impact system reliability. Along this continuum are contingency situations that LADWP has recently had to contend with, such as the sustained outages of most lines north of Sylmar Converter Station that occurred in late 2019 due to the Saddleridge Fire. All contingency cases are also simulated for our model of the 2020 LADWP system to facilitate comparison of the 2045 system with today. (As with all PCM modeling described in Section 1.4, the 2012 weather year is used for renewable energy resource profiles in both the 2020 system and the 2045 buildout.)

[53] The inclusion of contingencies as security constraints in PCM is possible and can theoretically result in one hourly dispatch that is higher cost but guaranteed not to drop load for all hours of the year even in the presence of any contingency considered. For this study, we pursued this approach for all contingencies under which LADWP is not permitted to drop load, but the run-time of such a simulation (even just for the LADWP system alone) was intractable. Additionally, simulating outages separately allows us to model system performance under more extreme circumstances where dropping some load is inevitable.

[54] "N-1 contingency" refers to an event in which one generation or transmission asset is taken out of service and "N-1-1 contingency" refers to an event where an N-1 contingency is followed by the outage of a second critical asset that occurs before the first can be repaired.

All contingencies LADWP currently models as part of its internal load flow modeling in the event categories defined by NERC TPL-001-4[55] as P1, P2, and P7 are modeled in PLEXOS as year-long outages, in addition to a subset of cases in the P3 and P6 event categories (which constitute N-1-1 contingencies) identified by LADWP as being of critical interest. The latter were selected because the full set of N-1-1 combinations would constitute tens of thousands of separate cases.

In all scenarios, we limit power flow to continuous ratings rather than allowing flow to reach the emergency 125% ratings LADWP defines for its transmission assets. This is done in part to compensate for nonlinear AC transmission constraints not being represented in the PCM and in part to reduce the computational complexity of constraining the use of the emergency ratings to only one hour at a time with some minimum duration of intervening cooling time. To further reduce computational complexity, the dispatch of load-shifting demand response determined in the no-outage reference case is applied to all outage cases. This is a conservative assumption, since the demand response could otherwise be dispatched more effectively in the outage cases to avoid shedding load.

One last consideration to note about the methodology used here is that since these extended outage simulations are intended to evaluate reliability rather than cost, the dispatch is not required to account for powering electrolysis to create any of the hydrogen needed to power H_2-CTs (unlike the reference “no-outage” case, which makes use of all available curtailed renewable energy and excess geothermal capacity to power hydrogen production). It is assumed that in emergency situations the hydrogen or ammonia can be purchased on the market even if fuel and transportation costs are high.

Table 21 summarizes information about the outage cases with a description of each category, the number of simulations that were carried out in each category, and the fraction in each that were able to meet all load.

[55] These standards published by NERC define the reliability requirements LADWP and other balancing authorities must design their systems to meet in planning assessments. The standards describe a range of contingency event types and system performance requirements for each in categories ranging from P0 to P7.

Table 21. Summary of Approach and Results for Year-Long Outage Simulations Modeling the Early & No Biofuels – High 2045 System Compared to 2020 Simulation

Contingency Type	Category Description	Load shedding permissible?	Contingency reserves (spinning and non-spinning) held	No. of cases provided by LADWP	No. of cases completed in PLEXOS[56]	No. cases with unserved energy		% of cases able to serve all load	
						2020	2045	2020	2045
P1 (N−1)	Single generator, line, or transformer loss	No	Yes	180	149	3	3[57]	98%	98%
P2 (N−1)	Single bus or breaker fault or opening of single line section	No	Yes	4	2	0	0	100%	100%
Critical N−1−1 contingencies identified by LADWP (P3 & P6)	Loss of multiple elements followed by system adjustments	Yes	No	39	38	15	2	61%	95%
P7	Single line-to-ground fault of multiple components sharing a common structure	Yes	No	24	24	2	2	92%	92%
NREL-created cases	Custom scenarios	Varies depending on severity of contingency	Varies depending on severity of contingency	N/A	4	2	3	50%	25%

[56] Some outage scenarios in each category could not be modeled since they refer to failures of system components that lie outside the topology modeled in the "Islanded" representation of the LADWP system.
[57] All three of these P1 contingency cases drop less than one MWh of load, which is well within the margin of error commonly seen across PCM solvers and slight perturbations to input data. For comparison, three P1 cases also drop load in the 2020 system model (all less than 100 MWh).

Although regulation reserves and flexibility reserves are held in all cases, contingency reserves are not held for outage scenarios in the critical N-1-1 (P3 & P6) and P7 categories. In keeping with the NERC definition, we assume that system adjustments have been made in order to serve load after a first component failure, with the system dispatcher calling upon the contingency reserves. The P2 and P7 categories represent momentary faults that generally clear within several cycles rather than sustained component outages, but they can persist when equipment fails to return to service and as such were included here as outage scenarios, with contingency reserves not held for the P7 category since contingencies in that category represent outages of multiple components.

As summarized in Table 21 the contingency cases portray the system built in the 2045 Early & No Biofuels – High scenario as generally reliable, with magnitudes of expected unserved energy well within NERC recommendations for all but the three cases in the P1 category that drop load. Although NERC does not allow load shedding for such N-1 contingencies, the cases each drop less than one MWh, an amount well within the margin of error in the PCM. In total, 10 of 215 long-duration outage cases run in PLEXOS are unable to serve all load. Figure 64 illustrates the total amount of energy that the system is unable to serve over the course of the year in each outage case in terms of normalized expected unserved energy (NEUE), an increasingly commonplace metric that gives intuition about the scale of the unserved energy relative to total annual load. Since load increases substantially between 2020 and the 2045 High scenario, plotting unserved energy relative to total load in ppm (where 1 part per million means one unit of load in every million cannot be served) allows direct comparison of the two years. Contingency labels are omitted for security purposes, but most cases that would require substantial load shedding are critical N-1-1 outages affecting two related in-basin assets or a combination of one in-basin asset and an associated into-basin circuit. This is true in both our model of the 2020 system and the 2045 Early & No Biofuels – High scenario. Two of the five cases estimated to require more load shedding in 2045 than in 2020 involve outages on multiple assets that bring energy into the LA Basin, including the case with the highest NEUE shown in Figure 64. The other three mainly involve high-rating circuits that move energy around the basin.

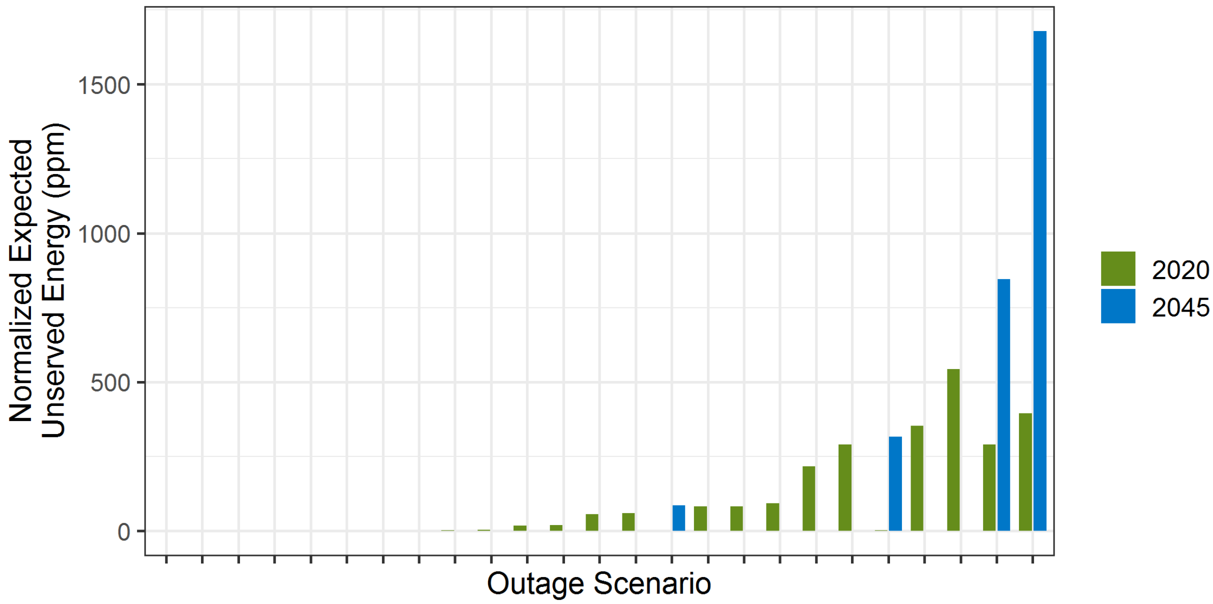


Figure 64. Normalized expected unserved energy by year and outage case comparing the 2020 LADWP system with the 2045 Early & No Biofuels – High scenario

All outage cases unable to serve all load are included (excepting an extreme NREL-created case for clarity). Each tick on the x-axis represents a separate year-long outage case; names of affected assets in each case are hidden for security purposes.

Figure 65 illustrates the timing of these outages. Today's system is most vulnerable in the high load periods that occur August–September. Although the 2045 system shows stress during the same period as these months are projected to continue seeing the highest loads, outages extend later into the year under the 2045 system, including in December when wind and solar resources are relatively poor.

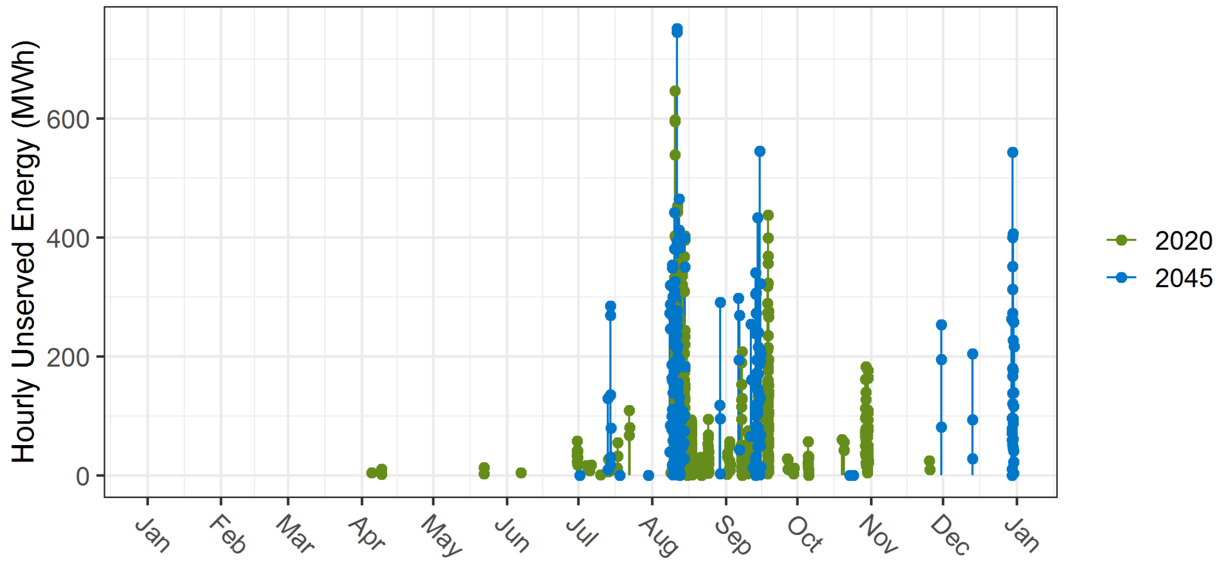


Figure 65. Timeseries of unserved energy by year for all long-duration outage cases (omitting an extreme NREL-created case for clarity)

Each dot represents the unserved energy of a unique outage case. The year refers to the simulation of that year's system as specified in the Early & No Biofuels – High scenario under the outage cases.

For example, December 30, as illustrated in Figure 66 (a), is a particularly bad day for renewable energy, requiring the H_2-CTs to run at full output during several periods in the day and with little low-cost generation to recharge batteries. Despite this, all reserve requirements are met and there is some unneeded RE-CT capacity available late in the day.[58] Figure 66 (b) depicts dispatch during an N-1-1 outage that affects two of three circuits in a key in-basin transmission path toward the west of LA. In this case, one 230kV circuit and one 138kV circuit are out of service with a 138kV circuit remaining online. The outage puts the remaining circuit at risk of overloading and requires power flows to be reduced near either end of the affected line, as well as elsewhere in the basin to a lesser extent. To continue serving all load without overloading the 138kV circuit, the system is forced into an inefficient dispatch that includes near-constant charging and discharging of in-basin diurnal storage. Although the system is severely limited in its ability to import geothermal, wind, and solar from the north because of the transmission constraint, batteries in the San Fernando Valley and the PHES at Castaic allow for the system to operate flexibly, with net generation profiles differing substantially from one bus to the next, in order to limit flows that would cause overloads on the affected circuits by cycling numerous times each day. Even with H_2-CTs and RE-CTs running full out, this flexibility proves to be insufficient late on December 29, and a small amount of load shedding (less than 4% of hourly load) is required that evening and throughout the morning and evening hours of December 30.

[58] The RE-CT experiences an unplanned outage throughout the day on December 29 and into December 30. Randomly chosen forced (unplanned) outages of conventional generators take place in the no-outage reference case and are applied to the outage cases to allow for comparison. This also makes results more conservative.

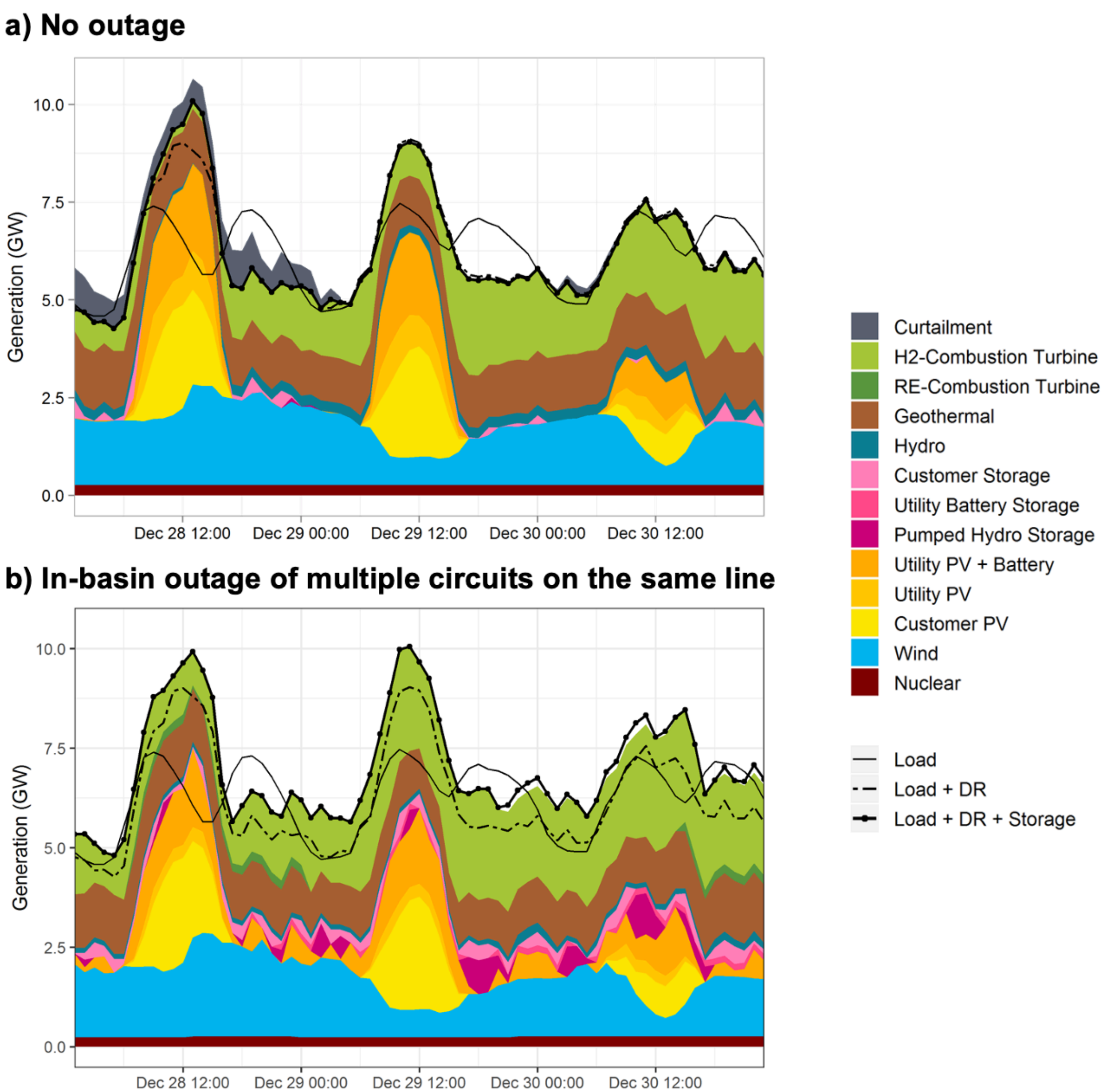


Figure 66. Dispatch over several days with poor renewable energy availability in (a) the reference (no outage) case and (b) an N-1-1 case affecting two of three circuits on a key in-basin transmission path

As the case study above highlighted, renewably powered combustion turbines play a critical role in managing the long-duration outages. That said, as Figure 67 shows, in the vast majority of situations in which LADWP loses one or more critical assets, the increase in generation from H_2-CTs and RE-CTs that is required to meet load in all hours is minimal. In 179 of the 215 long-duration outage cases, combustion turbines provide 10% or less of the system's total energy in the last six months of the year (where all load shedding occurs), as compared to 9% in the no-outage case. The remainder rely on CTs for 11%–25% of energy in that time frame, and three of the four scenarios that make use of CTs the most are extreme scenarios created by NREL.

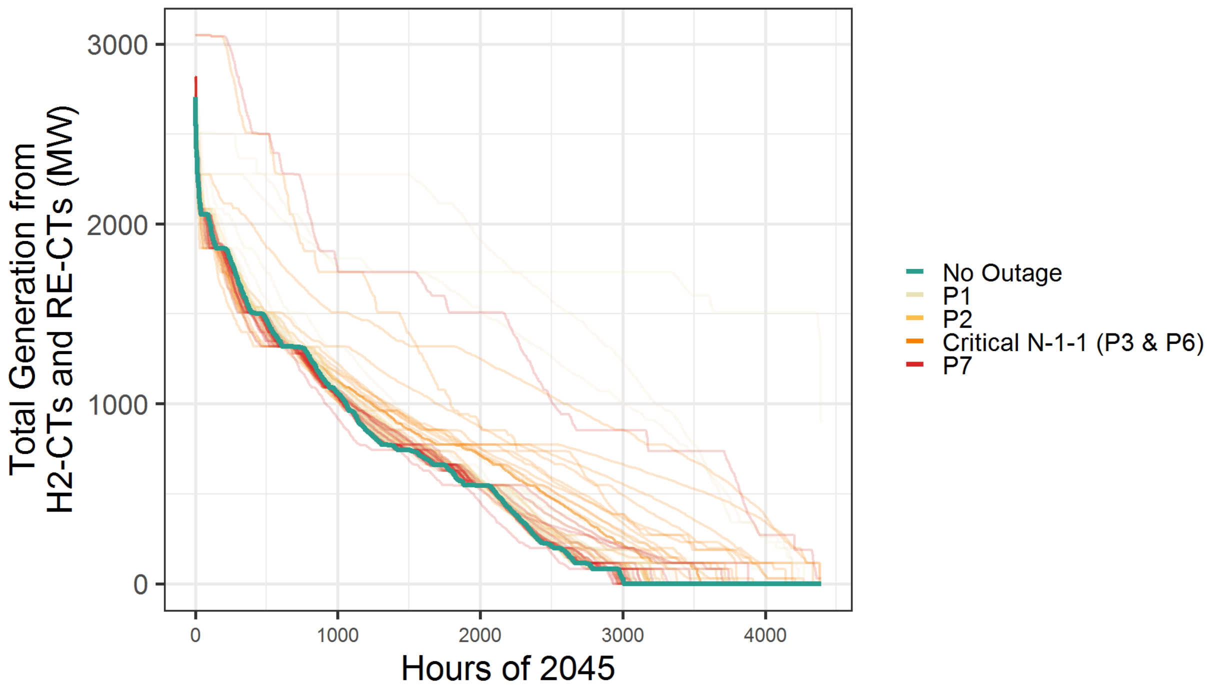


Figure 67. Duration curves depicting generation in all hours from H_2-Combustion Turbines and RE-Combustion Turbines in all extended outage simulations, with hours in order of descending total generation and a separate line for each outage case, colored by its contingency event category

Note: Only the second half of the year, where all dropped load occurs across cases, is illustrated here for clarity.

These extended outage results are an indication that the generating portfolio and transmission upgrades in the LA100 scenarios can maintain reliable operation even when access to out-of-basin resources is limited and highlight the role of in-basin dispatchable capacity constructed to replace existing gas-fired generation. They also highlight the continued need to balance costs and reliability in the face of uncertainties, such as the possibility of increased fire risk to transmission assets.

4.2.3 Unexpected, Rapid Outages (Contingencies)

The final element of analysis to consider system reliability is the response to contingency events. The previous two sections consider the ability of the system to balance supply and demand even after outages. This includes some elements of transmission reliability including thermal overloads. However, the PCM tools used do not analyze the reliability of the system in the seconds and minutes following an actual outage, nor do they analyze in detail the complex flows of power across the entire AC transmission network. A transmission or generator outages (which can occur in less than a second) can result in a large change in the flow of energy on the transmission network, potentially overloading the system.

The PSLF tool was used to analyze the flows on the LADWP transmission system after a failure of many individual elements or combinations of elements and ensure overloads would not risk additional failures.[59]

This section summarizes the steady-state post-contingency analysis results and focuses on the transmission line upgrades in LADWP that would be required to meet the reliability criteria in 2030 SB100 – Stress and 2045 Early & No Biofuels – High scenarios. Results are based on the short-duration ratings (rating 2) of the transmission elements, where ratings can typically be sustained for 2 hours. A detailed discussion about steady state and transient contingency analysis results for these two scenarios is provided in Appendix E.

The detailed list of violations is provided in Appendix E. In the 2030 Base Case, a total of 30, line violations and 9, transformer violations were found based on the aggregate of N-1, N-k (when more than one element is removed from service at the same time by a contingency), and N-1-1 contingency analyses. The Monsoon Sensitivity identified six violations with a slight increase in severity (less than 3.5%) and six new violations. The Northern Imports Sensitivity identified 27 violations with an increase in severity, in which the increase in severity is much higher than that observed in the monsoon sensitivity. The highest increase in severity observed is for the two 230 kV Tarzana-Olympic lines that see an increase of over 100% in their loadings above their worst loadings in the base case. Such a large increase in loadings is expected because of the observations made earlier regarding the severity of the Northern Imports sensitivity. Eight new thermal violations were also found in the Northern Imports sensitivity. The High Load Stress VIC-LA Sensitivity identified a total of 21 more severe thermal violations compared to those found in the contingency analyses in the base case were found, of which 16 were lines and five were transformers. The increase in severity is also much higher than that observed in the Monsoon sensitivity. The highest increase observed is for the three 230 kV Tarzana-Olympic lines that see an increase of over 90% in their loadings above their worst loadings in the base case. The increase is less severe than that observed in the Northern Imports sensitivity. Eight new thermal violations when compared to the base case were also observed.

For the 2045 simulations, we identified both increases in violation severity and new violations compared to the 2030 cases. For the sensitivities, more severe and new thermal violations compared to both 2030 simulations and the 2045 base case simulations were identified. Table 22 summarizes the results, with details provided in Appendix E.

Table 22. Violations Identified in 2045

Case	Increase in Severity Relative to 2030	New Violations Relative to 2030
Base	15	10
Monsoon	4	1
Northern Imports	14	2
VIC-LA	1 (negligible)	1

[59] Only N-1 and N-k contingency analyses were performed for the sensitivities because these sensitivities already modeled a very stressed transmission system (with highest loads possible for the two scenarios) of LADWP. Designing a system to withstand N-1-1 contingencies under these stressed conditions would be beyond the current practice today.

From the above analysis, a total of 45 lines and 11 transformers will need to be upgraded by 2030 if no violations under Base Case and the three sensitivities are acceptable. Of these, 38 lines and seven transformers have loadings above 110%.

In 2045, four additional lines and 10 additional transformers will also need to be upgraded. Also, by 2045 24 lines and seven transformers that needed upgrading in 2030 will need to be further upgraded in 2045. However, only eight of the 24 lines and two of the seven transformers exceed the highest 2030 loadings by more than 10%.

Overall, the contingency analysis identifies a significant number of elements on the transmission network that may require upgrades. These are in addition to the upgrades included in the RPM analysis that have been calculated in the total system cost. Because the contingency analysis was performed for only the most difficult scenarios (Early & No Biofuels), it is not possible to do a complete cost comparison. Furthermore, it is difficult to estimate the costs of the specific upgrades given the site-specific nature of the upgrades. For example, estimating the costs of a transformer upgrade at a receiving station requires understanding the available land, LADWP-specific construction practices at that site, and other factors. As a result, case-by-case analysis will be required to determine the cost and feasibility of the specific upgrades, as well as comparison to alternative.

However, it is important to note that there are a number of possible solutions to addressing these violations and which vary in cost. Actual physical upgrades of the equipment represent a likely upper bound to these costs, and some of the upgrades are likely necessary regardless of scenario.

There are a number of possible approaches that could either supplement upgrades (perhaps reducing the size of the upgrade or delay the upgrade) or even eliminate the need for an upgrade. These approaches include:

1. **Repositing In-Basin Dispatchable Generation:** All LA100 scenarios develop significant in-basin dispatchable capacity, located at all four of the current LADWP generation sites. Iterative power-flow analysis may reveal that moving some of this new capacity could lower upgrade costs. Moving new capacity from one site to another can relieve specific constraints (while possibly introducing new constraints). This analytic process could be repeated in an iterative fashion, comparing the quantity of upgrades needed and site-specific costs to find the combination with the lowest overall upgrade costs. As a starting point, the power flow analysis suggests moving some of the in-basin capacity from the Valley generation station to Scattergood. This change is reflected in Table 7, which should act to relieve some of the violations observed in this section.
2. **Additional DC or Flexible AC Transmission Systems (FACTS):** AC power cannot typically be steered. This means that even under steady-state conditions the system is inherently limited by its weakest component. This also means that there is always under-utilized transmission capacity—transmission elements that could actually carry more power, but attempting to deliver more power on this element would overload other elements. LADWP already utilizes both DC transmission and phase-shifting transformers that allow various degrees of control over power flow. Additional deployment of DC or FACTS devices can allow the system to increase the flow on the elements that are operating below their thermal limits, essentially allowing greater overall system capacity.

3. **Dynamic Line (and Equipment) Ratings:** The actual capacity of transmission elements (transformers, lines, protection equipment) are typically rated on a single, or very limited set of conditions, largely based on how hot they will get at a specific temperature that is essentially assumed not to vary. Cooler weather, or windy conditions can cool some transmission elements (primarily overhead lines). This means that they could sometimes carry more power than their "normal" ratings. Dynamic line rating schemes might even consider the ability of transmission elements to carry power more than steady-state conditions would normally allow for a short period of time (such as under peak demand conditions) in anticipation of cooling later in the day. Even if contingencies occur under hot weather conditions (where there is reduced benefits), the information provided by active equipment monitoring can be combined with FACTS devices to optimize power flow and maximize system reliability.
4. **Dynamic Response to Contingency Events:** Contingency analysis often applies a uniform threshold rating for what is considered an overload. However, the actual impact of an overload to an element on the transmission system is a function of both the increase in power (current) AND the amount of time of the overload. The impact will vary by element type, with overhead conductors typically able to handle larger increases in power for shorter time periods, while other components such as underground cables and transformers are more sensitive. This problem is compounded by the challenge of understanding the state of the system at any given time, and the ability to control the flow of power across individual elements. As a result, the transmission system has to be significantly "de-rated" to allow for a contingency event that avoids damaging overloads. Improved understanding of the state of the system, combined with FACTS devices and a more dynamic response to contingency events, can potentially avoid the need for upgrades by increasing the utilization of transmission assets. For example, inverter-based resources (including battery storage) or sheddable loads can respond to an event with a few seconds via a variety of control schemes. Under contingency conditions, this could allow for potentially greater very short-term overloads on non-sensitive components of the transmission system. Fast-response resources can reduce the duration of the overload from minutes to seconds, while reducing reliance on partially loaded thermal in-basin capacity providing operating reserves. In-basin capacity will still act to provide energy to replace the batteries or shed load during extended outrages, but can be operating as non-spinning resources, reducing costs and emissions.

5 What Don't We Know?

The LA100 study shows that there are many options for LADWP to reach LA's 100% renewable energy target. The actual investment pathway can be customized from the scenarios presented in this report to reflect the city's priorities.

This study represents a profound step toward understanding some of the issues associated with reliable operations of a 100% renewable energy system, in particular by more accurately capturing the availability during peak periods of energy-limited resources such as storage, and by more accurately capturing how to maintain balance with 100% renewable energy supply when extreme events occur, such as major transmission outages.

Nevertheless, the study makes a range of analytically based assumptions that are important determinants of the identified technology pathway and their associated costs but are inherently uncertain. These assumptions range from the modeled projections of load growth that incorporate impacts of energy efficiency, climate change driven increases in average temperatures, and adoption of electric vehicles, to analytically derived assumptions about the availability of demand response, to assumptions about the future costs and performance of generation and storage technologies, and the future costs of fuels. While some of these assumptions were evaluated through scenario distinctions and sensitivities, we want to stress that changes to these assumptions can have substantive impacts on results. The study is designed to understand various drivers, constraints, and interactions associated with pathways to 100% renewable energy, and not to predict specific outcomes in terms of capacity or costs.

Still, a few areas in our assumptions warrant further discussion due to uncertainties in how the power system could evolve and are summarized below.

5.1 Hydrogen Economy

To maintain reliability in the modeled 100% renewable systems, the study made assumptions about renewable options for firm capacity that can be sited in the LA Basin and run for days, namely renewably fueled CTs and fuel cells. To supply the CTs, we assume either a transition fuel, such as biofuel, or hydrogen fuel produced from 100% renewable electricity.

Biofuels are commercially available today. As described in Section 2.4.3, biogas can be procured in small quantities, such as from landfills and municipal solid waste plants, but are not at the scale needed for the power system unless LADWP purchases just the renewable energy credits to offset continued natural-gas combustion. Refined biofuels, such as ethanol and biodiesel, are available at the power-system scale and could generate electricity through a CT or reciprocating engine at capital costs similar to a natural-gas plant, but with a much higher fuel cost. This technology represents a commercially available option but is not a scalable solution for the country. We therefore treat biofuels including biogas as a transition fuel while hydrogen-based technologies (or a currently unknown option for seasonal storage) mature in commercial availability.

Hydrogen or hydrogen-derived fuels represent the best seasonal storage option for Early & No Biofuels, which does not allow biofuels, but this technology is early in commercialization with regard to the power system. The electrolyzers needed to produce hydrogen are available, but at smaller quantities relative to the supplies needed for the future power system. Ideally, this hydrogen would be produced for a broader economy than just LADWP to make better use of the infrastructure required for a hydrogen fuel supply.

Our study makes several assumptions that would need to be rigorously evaluated if this hydrogen option is pursued, including:

- Where to site the fuel storage. For quantities of fuel needed for seasonal fuel storage, this might be best stored outside the city and piped or trucked in as needed.
- How to size and site the electrolyzers with regards to fuel storage and transmission availability during periods of excess renewable generation, among other factors.
- Public acceptance of fuel storage at the in-basin generating sites, particularly for ammonia if hydrogen is stored in that form.

Fuel cells remain another option, but with even greater uncertainties. The advantage of fuel cells over CTs is the potential to have zero-emission, distributed generation across the city. But the infrastructure to transport hydrogen fuel to distributed locations is a significant departure from current utility or city plans, so we excluded that option. We also did not evaluate options for customer resilience, which could also increase the market for fuel cells. Nevertheless, a very different vision for on-site fuel production or a fuel distribution network could drastically change in-basin generation and associated transmission, particularly at the thermal generating sites.

5.2 Transmission Infrastructure

Because of the unique challenges in building new transmission infrastructure, the costs and feasibility of transmission upgrades are among the most uncertain inputs to modeling of pathways to 100% renewables. Our representation of transmission investments required to reach new renewable resources does not differentiate between construction of new transmission capacity and the purchase of rights along existing transmission corridors. This is of interest mostly regarding renewable resources interconnected at IPP. More detailed study would be required to assess the feasibility and cost optimality of purchasing transmission rights on existing corridors and the construction of new lines.

Simplifications were made to represent transmission infrastructure and upgrade costs in the capacity expansion and production cost modeling stages. For these modeling stages, we assume that the transmission system can be operated at closer to the thermal limits of the network, based on implementation of a variety of techniques and technologies that exist now, or are in the early stages of deployment. Advanced transmission technologies including flexible AC transmission, dynamic line ratings, and the increased use of fast response resources could increase transfer capacity along existing routes that are heavily congested and cannot be easily upgraded. However, the specific options were not modeled, particularly as the specific transmission management technologies deployed will be very site specific. These technologies were also not modeled in the contingency analysis and demonstrate the need for alternative approaches to ensure reliability if all the identified upgrades are not feasible.

5.3 Evolution of the Power System Outside of LADWP

Actions taken by other utilities and system operators throughout the Western Interconnection will impact LADWP's ability to build and utilize resources along paths with shared ownership as well as its ability to import and export energy to and from other balancing areas. The two largest uncertainties that affect the study are:

- **Decarbonization efforts across the West**. We represent in our modeling state-specific renewable and clean energy targets for all policies enacted as of May 2018. The net effect of these targets leads to 67% renewables in the rest of the Western Interconnection by 2045. If in actuality most of the West achieves closer to 80%–100% renewables by 2045, there would be greater competition for renewable resources, potentially resulting in somewhat increased costs, potential changes in the locations of resources, and the associated transmission rights, upgrades, or builds to access those resources. In addition, given that all entities would likely be deploying substantial amounts of wind and solar, the opportunities for LADWP to sell surplus generation during times of high solar and wind output would likely be diminished, and associated curtailment increase. Note however that our core PCM simulations do not allow purchases or sales of energy. Development of new renewable resources could also change the operation of the transmission system, particularly in lines shared with LADWP's neighboring systems, and additional power flow analysis will be needed to consider this evolution.

- **Market participation**. Integration with any market has the potential to lower costs by allowing arbitrage across time and space, thereby reducing real-time costs of services (generation, operating reserves) and, potentially, avoiding some level of investment/fixed costs (e.g., if a single resource can meet two entities' requirements). We showed that participation in an idealized WECC-wide energy market would allow for reduced reliance on the high-cost in-basin firm capacity assets and reduced curtailment by exporting (selling) surplus renewable generation to neighboring utilities—both of which reduce costs. An extension of these results would be that market participation may allow for reduced capacity of some portion of the in-basin firm capacity resources (given the opportunity to substitute purchased energy or other electricity services) and lower cost options to purchase electricity for hydrogen production when renewable electricity would otherwise be curtailed. However, given the existing transmission constraints, there may not be sufficient transmission capacity to ensure that such imported services could be relied on, and further analysis would be required to evaluate this. Overall, we expect that participation in a broader market would not drastically change the core findings, but costs of a 100% renewable transition would likely decrease, and LADWP would likely have an increased concern in maintaining reliability in the face of market uncertainty.

5.4 Customer Participation

Many customers today seek a new relationship with their power system and utility. This changing role of the customer could have a profound impact on both electricity demand and renewable supply, impacting the options to get to 100% renewables. The LA100 study assumes significant changes to the traditional role of the customer, with loads (particularly EV charging) providing an important source of flexible load and demand response, including provision of operating reserves in response to contingency events. However, most of the demand for electricity is still assumed to be inflexible. The study does not consider sweeping changes to customer control that could come with different rate tariffs, advanced communications, and networked end-use technologies. Such advanced demand response could potentially replace in-basin firm capacity.

Particularly in the in the Early & No Biofuels scenario, higher-cost H_2-CT peaking capacity is required to meet periods of extended transmission outages or periods of low renewable resource availability. These plants generate with high effective levelized costs of energy, and if this cost were compared to customers willingness to forgo energy with suitable compensation, the scenario could reduce its dependence on higher-cost peaking capacity, resulting in an overall lower cost.

Understanding the potential roles of the customer would require detailed analysis of the LADWP customer base and sources of demand that may be deferred for hours or even days at a time. Such demand response schemes have never been implemented at scale but may be feasible with advanced communications and controls that allow greater customer participation.

5.5 Climate Change

The study assumes rising temperatures as part of the projections for customer electricity demand, and also evaluates the impact of historical variations in wind and solar availability. However, the study does not consider how wind and solar supply patterns may change with climate change.

The study also evaluates the ability of LADWP to serve load during transmission outages, which may become more frequent due to wildfires. But many other impacts of increased wildfires, ranging from changes to electricity use patterns to reduced output of solar panels was not considered. Other impacts of increased temperature, such as accelerated degradation of transmission equipment, were not considered.

5.6 Feasibility of Accelerated Deployment

The LA100 study identified specific locations for new capacity based on resource availability, assumed competition with other jurisdictions in the West, and in the case of locations within the city, detailed siting analysis. But the study does not fully assess the challenges associated with achieving the substantial acceleration in the speed of deployment of generation, storage, and transmission resources required in order to achieve the 100% renewable system. These challenges include formal siting and permitting, manufacturing supply chain availability, available labor force, and, ultimately, development of a detailed construction schedule that ensures that supply and demand can continue to be balanced as new resources are brought online.

On supply-chain and labor availability, the LA100 study estimates labor requirements associated with the deployment pathways but does not evaluate the availability of labor to serve these requirements. That said, despite the levels of deployment observed representing a large acceleration in procurement for LADWP, these changes remain small in the context of the international industries of wind, solar, and storage manufacturing, construction, and operation. Of course, if other jurisdictions rapidly scale up clean energy investments contemporaneously, renewable energy labor forces could be in high demand. Therefore, early planning would help ensure the availability of the workforce and adequate manufacturing supplies to support these deployment rates.

Finally, as LADWP continues to progress toward a 100% clean energy system, detailed construction schedules will need to be developed to ensure that reliability and energy balance can continue to be maintained as new resources come online and others retire. This poses a significant coordination challenge, but given that the large majority of investment is in generation and storage assets, existing resources can continue to provide key services as new resources are brought online—this also highlights the potential benefits of allowing some flexibility in the timing of new resources or the retirement of existing resources.

Appendix A. Description of RPM

RPM is a capacity planning and dispatch model specifically designed to simulate the evolution of a regional power system, such as a utility service territory, state, or balancing authority, from present day through 2050. The model is a mixed-integer linear program that finds the least-cost investment and dispatch solution subject to a suite of physical and policy constraints. The model chooses the type, location, size, and timing of future generation, storage, and transmission technologies. The model uses a highly spatially disaggregated representation of grid infrastructure and generation resources (down to the individual unit and line) and multiple solar and wind resource regions.

RPM also maintains a representation of surrounding regions in order to capture inter-regional transactions and the impacts of these transactions on the region of interest. To accomplish this, RPM represents the region of interest with a very high level of detail to characterize the generation and transmission topology—specifically, generating units and transmission lines are represented individually, with nodes representing electrical busses connected to individual generators or loads, or connection points between transmission elements. A simplified representation of the rest of the interconnection in which the region of interest resides is included in the model to account for boundary interactions (see Figure 10), with each balancing area (BA) modeled individually as an aggregated unit. In other words, RPM is a combined nodal (for nodes within the focus region) and zonal model (for zones outside the focus region). There are 36 model BAs represented throughout the Western Interconnection.

A unique aspect of RPM relative to most capacity expansion models is that dispatch decision-making is conducted using chronological hourly time-steps for a set of representative days sampled throughout a year. Statistical analysis (clustering) is conducted on hourly load shapes for all days in the year, and each day is characterized as either a low, mid, or high load day, or a low variable generation day. In addition, the day with the highest hourly load is selected as a fourth "peak day." For the low, mid, high, and low variable generation categories, a single day from each bin is statistically selected as the most representative day. These five representative days are subsequently used to model dispatch. Hourly dispatch is simulated for each the representative days. This dispatch is then scaled to represent dispatch for the full year. In addition to energy balance, RPM also considers the provision of reserves—including spinning reserves, regulation, and flexibility—and many generator performance and operational constraints. Transmission constraints are represented with a transport (pipe-flow) model.

RPM is specifically designed to consider the characteristics of wind and solar technology resources—that is, location-dependence, variability, and uncertainty—in its investment decisions. RPM also accounts for the costs of renewable interconnections, declining capacity credit and increasing curtailment rates, operating reserve requirements, and transmission congestion.

RPM formulates an optimization problem that minimizes overall system cost, including capital costs, fixed and variable O&M costs, fuel costs, and start-up costs. All costs in the objective function, including operating costs (e.g., fuel and variable O&M costs) and fixed costs (e.g., amortized capital and fixed O&M costs), are annualized. Several constraints are designed to characterize power plant operation, transmission dispatch, grid reliability, and capacity expansion.

A.1 Generation and Storage Technology Costs

Projections of the costs of storage and renewable generation technologies, including wind, geothermal, utility-scale solar PV, residential and commercial PV, concentrating solar power (CSP), and biomass, are derived from NREL's Annual Technology Baseline (ATB) (NREL 2019). For each technology, the ATB provides three different projections of future costs (including capital, financing, grid connection, and fixed and variable O&M) from present day to 2050: constant, mid, and low. All scenarios explored in this chapter assume *mid* cost projections from the ATB. Figure 68 shows an example of capital expenditure (CAPEX) cost projections for utility-scale PV.[60]

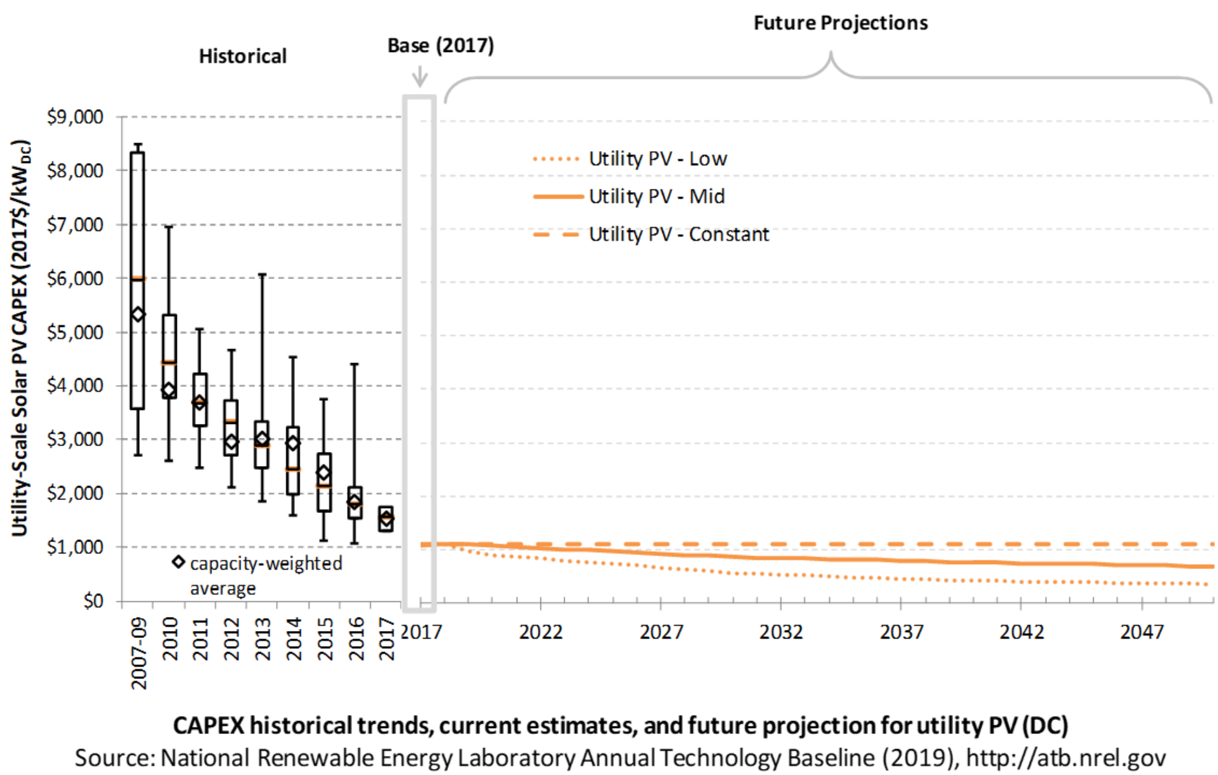


Figure 68. CAPEX historical trends, current estimates, and future projections for utility-scale PV

[60] Cost projections for all technologies can be obtained at "Annual Technology Baseline," NREL, https://atb.nrel.gov/.

A.2 Fuel Prices

Fuel prices for fossil and nuclear generation units in RPM are derived from two sources. Annual average prices for natural gas, coal, and uranium are from the Energy Information Administration's (EIA) 2018 Annual Energy Outlook (AEO2018) *Reference Case* projections for the Pacific region.[61] In order to represent monthly variation in natural gas prices, seasonal price factors were developed based on historical monthly average prices for natural gas obtained from LADWP. These price factors were then applied to the annual average projections to yield monthly average natural gas prices from present day to 2045. Figure 69 shows the natural gas fuel price projection used for this suite of scenarios.

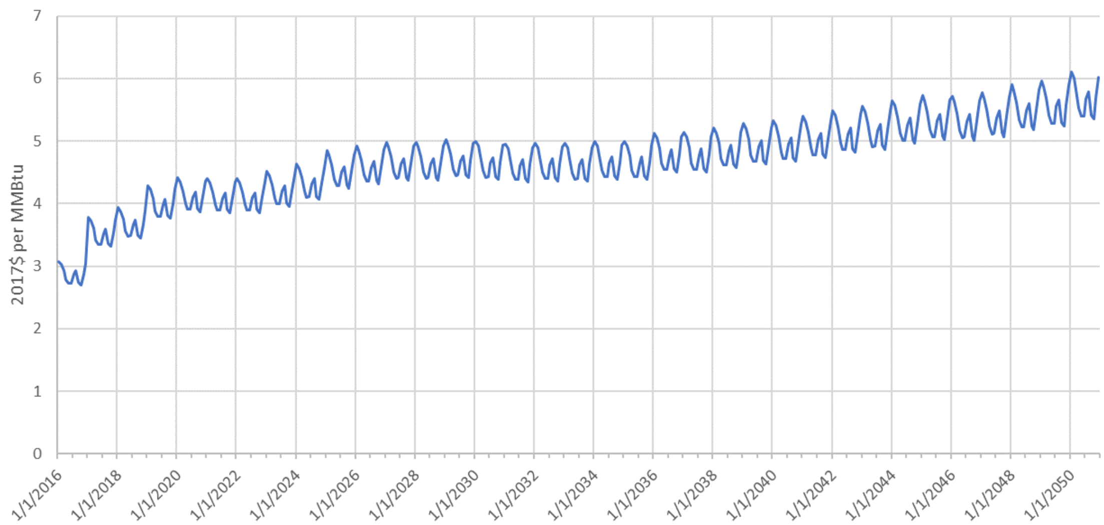


Figure 69. Natural gas fuel price projection

[61] The AEO presents yearly modeled projections and analysis of energy topics. See "Annual Energy Outlook," EIA, https://www.eia.gov/outlooks/aeo/. Details on the fuel supply module, including regions, can be found at "Oil and Gas Supply Module: NEMS Documentation," EIA, May 15, 2020, https://www.eia.gov/analysis/pdfpages/m063index.php.

Appendix B. Data Sources for Bulk System Capacity Expansion (RPM)

This appendix provides additional details on assumptions and methodology used by NREL's RPM Capacity Expansion Model. Table 23 provides information about NREL-defined parameters for RPM.

Table 23. Base Model Parameters

Name	Information
Geographical Scope	Western Interconnection – zonal representation, LADWP - nodal representation. Nodes and zones are defined originally by TEPPC (2020)[62]
LA planning area	LADWP service territory. Assumes Burbank and Glendale are in Southern California Edison (SCE) BA for planning purposes
Technologies modeled (before exclusions)	Biofuel, CC, Coal, Coal Cogen, CSP without TES, CSP TES, CT, Gas Cogen, Gas Steam, Demand Response, Battery Storage (multiple durations), Geothermal, Hydro, Hydro Fixed, H_2-Combustion Turbine, RE-Combustion Turbine, Nuclear, Oil, PHES, PV Fixed, PV Tracking, PV Rooftop, PV+Battery (multiple durations), Onshore and Offshore Wind63
Years Analyzed	Which year data corresponds to. These are the years for which RPM needs year-changing values: 2020, 2025, 2030, 2035, 2040, 2045

Table 24 describes load data. For the LA100 study, load data inside the LADWP service territory are modeled at a nodal level, and data outside of the territory are modeled by BA.

Table 24. Load Inputs

Name	Information	Source
Load growth	Annual load growth (%/year)	TEPCC 2024 (outside LA), NREL dsgrid model (within LADWP) (see Chapter 3 for explanation)
Peak load growth	How much the peak load day grows per year (%/year)	
Load	8760 load profiles (MW); combines with node-load participation set to determine node load	

[62] Western Electricity Coordinating Council (WECC) Transmission Expansion Policy Planning Committee (TEPPC) originally published as part of the "2020 Study Report – 10 Year Regional Transmission Plan" (wecc.biz)

[63] While all these generation types are modeled, not all are allowed to be built in the optimization. Coal, CSP without TES, Cogeneration, and Hydro are not investment options, although existing generators of those types are considered.

Table 25 lists renewable data sets. Renewable data are typically defined at the RPM region level.

Table 25. Renewable Data Sets

Name	Information	Resolution	Source
Renewable capacity factor profiles	Representative wind, solar PV, and concentrating solar power (CSP) capacity factors profiles (by percentage), aggregated or clustered to a regional level	Technology, class, region, hour	NREL reV model,[64] using 2012 weather year
Hydro operational constraints	Seasonal/monthly, weekly, and daily energy minimums and maximums	Node, hour	TEPPC
Wind/solar power density	Packing density of wind or PV in terms of MW of DC module capacity (MW/km^2); 3 MW/km^2 for wind; 32 MW/km^2 for solar	Technology	NREL reV model
Wind/solar/CSP supply	Available resource in each renewable energy region (km^2)—varies	Technology, class, region	NREL reV model

Table 26 lists transmission data used by RPM. In general, most data outside LADWP are defined at the BA level, while most data inside LADWP are defined at the nodal level. These data are originally derived from Western Electricity Coordinating Council (WECC) Transmission Expansion Power Planning Committee (TEPPC) data sets and revised with data from LADWP.

Table 26. Transmission Data

Name	Information	Value	Source
Transmission topology	Nominal voltage level (kV), Existing forward and backward rated capacity on lines connecting two nodes (MW), Distance between two nodes (km), interface limit between BAs	Misc.	TEPPC/ LADWP data
Solar/wind transmission distance	Transmission distance to connect node to wind or solar region (km)	Misc., varies by resource region and technology	GIS
Capital cost	Cost to build an AC or DC line ($/MW-km)	Varies based on voltage rating of line ($1000/MW-km to $19,000/MW-km). LDWP specific costs for known line upgrades	EIPC, TEPPC, ERCOT and ReEDS; LADWP data
Spur line cost	Cost to build a spur line to a wind or solar region ($/MW-km)	$2274/MW-km	EIPC 2012[65]

[64] "reV: The Renewable Energy Potential Model," NREL, https://www.nrel.gov/gis/renewable-energy-potential.html.
[65] "EIPC Documents," Eastern Interconnection Planning Collaborative, https://eipconline.com/eipcdocs.

Name	Information	Value	Source
Hurdle rate	Cost threshold to transfer power between regions ($/MWh)	Varies by region; LADWP exporting = 5.25 LA importing = 7.44 to18.72	TEPPC
Transmission ownership	LADWP ownership share	Varies	LADWP (internal)
Time to permit/site/construct new transmission	Currently disallow new or upgraded transmission (that is not already under development) before 2025	Implicitly, 6+ years	
Transmission Loss Rates	Based on the LADWP Real Power Loss Factor Assessment	4.8%–6.2% depending on the line	LADWP

Table 27 lists power plant performance data for existing plants. Data for plants outside LADWP originates from TEPPC documents, while plants within LADWP were updated as much as possible with LADWP data sources.

Table 27. Cost and Performance Data for Existing Power Plants

Name	Information	Value	Source
Thermal generator properties	Type, location, capacity, pollution rate, start cost ($/MW/start), startup fuel (mmBTU/MW/start), forced and planned outage rates (fraction), minimum generation level (fraction of nameplate), ramp rate (fraction of capacity/min), minimum on/off time (hours), heat rate (mmBTU/MWh)	Varies	LADWP data sets (LADWP-owned plants), TEPPC (rest of WECC)
Additional hydropower factors	Hydro monthly energy limits (GWh/hr); Scaled to match 2013 limits, which is a more “average” hydro year (2012 is a wet hydro year, so was overly optimistic about hydro availability)	Varies by plant and season	TEPPC
Pumped storage round trip efficiency	Specified for each individual plant	Varies by plant; Castaic = 65.8%	TEPPC/ LADWP data set
Natural gas price	$/mmBTU	Varies by year and region	AEO 2019; LADWP
Coal price	$/mmBTU	Varies by year and region	AEO 2019; LADWP
Plant retirement capacity factor	Annual capacity factor below which it is assumed a plant would retire	CT=0.001 CC=0.04 Coal=0.07 Gas Steam=0.001 Nuclear=0.1	Model Assumptions; intentionally chosen to be quite low to not prescribe unwarranted early retirement

Table 28 lists power plant cost and performance data for new builds. Some data incorporates specific conditions based on feedback from LADWP.

Table 28. Cost and Performance Data for New Builds

Name	Units	Resolution	Source
Capital costs	$/MW	Technology, class, year	Annual Technology Baseline (ATB)[66] and EIA
Fixed O&M	$/MW-year	Technology, class, year	ATB and EIA
Variable O&M	$/MWh	Technology, class, year	ATB and EIA
Pollution rate	lb/mmBTU	Technology, pollutant	EIA
Fuel price	$/mmBTU	Fuel, year	EIA, LADWP
Startup cost	$/MW/start	Technology	EIA
Startup fuel	mmBTU/MW/start	Technology	EIA
Forced outage rate	Fraction	Technology, class	TEPPC
Planned outage rate	Fraction	Technology, class	TEPPC
Minimum generation level	Fraction of nameplate capacity	Technology, class	TEPPC
Ramp rate	Fraction of capacity/min	Technology, class	TEPPC
Minimum on/off time	Hours	Technology, class	TEPPC
Minimum plant size	MW	Technology, class	TEPPC
Heat rate	mmBtu per MWh	Technology, class, year	EIA
CSP thermal energy storage (TES) cost	$/MWh (capacity)	Year	ATB
CSP field cost (normalized to solar multiple [SM]=1)	$/MW	Technology, class, year	ATB
Hydro monthly energy limits	GWh/hour	Node, hour	TEPPC
CSP heat exchanger losses	MWh per MWh	Technology, class	Input
Storage roundtrip efficiency	%	Technology, class	ATB
Storage dissipation (standby losses)	%/hour	Technology, class	ATB

[66] "Annual Technology Baseline," NREL, https://atb.nrel.gov/.

Table 29 lists planned retirements and builds. Data for units outside LADWP is derived from TEPPC, Ventyx, and other sources. Data for LADWP units is updated as possible to be consistent with LADWP planning documents.

Table 29. Planned Retirements and Builds

Name	Source
Planned plant capacity	TEPPC, Ventyx (WECC), LADWP
Planned plant retirements	TEPPC, Ventyx (WECC), LADWP
Prescribed renewable capacity	TEPPC, Ventyx (WECC), LADWP
Planned transmission upgrades and developments	TEPPC, Ventyx (WECC), LADWP

Table 30 lists data regarding local, state, or national policies that impact capacity expansion and operation. Most of these data involve what the actual policies are, but they also include how they are enacted in these models.

Table 30. Policy and System Operation Data Elements

Name	Value	Information	Source
Planning reserve requirement (outside WECC)	Varies based on NERC region; 11%-16%	NERC-reference capacity reserve margin (fraction of peak load)	NERC67
LADWP planning reserve requirement	23%	May be translated from LADWP reliability requirement (Loss of load expectation of similar performance metrics)	LADWP
Renewable energy credit (REC) price	Endogenously determined within RPM		
State renewable portfolio standard (RPS)	%	Fraction of load required to be renewable, including general and carve-out requirements	DSIRE68, state policy, fraction of load in a state that is served by investor-owned utility (IOU), municipality, etc. as of May 2019
RPS Trading rules	Varies		
Federal PTC value and trajectory	Varies based on year	Annual PTC value ($/MWh)	Federal tax code

[67] "Reliability Assessments," North American Electric Reliability Corporation, https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.
[68] "Database of State Incentives for Renewables and Efficiency," N.C. Clean Energy Technology Center, http://www.dsireusa.org.

Name	Value	Information	Source
Federal investment tax credit (ITC) value and trajectory	Varies based on year	Annual ITC value ($/MWh) and applicable technologies	Federal tax code
CA carbon price	Escalates over time	$/metric ton	California Air Resources Board

Table 31 details the assumptions of operating reserves as modeled in RPM.

Table 31. Summary of Operating Reserve Modeling in RPM for the LADWP System

Parameter	Assumption	Source
Contingency	600 MW with 10 min response	NREL assumption
Regulation	1% of load + 0.5% of wind energy + 0.3% of PV capacity during daylight hours. 5–10 min response	NREL assumption
Flexibility	10.0% of wind energy + 4.0% of PV capacity during daylight hours. 60 min	NREL assumption
Movement cost providing regulation	Varies by technology	Hummon et al. 2013[69]
Renewable eligibility	Wind and PV can provide reserves after 2025	NREL assumption

Table 32 lists values RPM utilizes in its cost optimization and analysis.

Table 32. Financial Data Used in RPM

Name	Value	Information	Source
Inflation Rate	2.5%		ATB2019
Capital Recovery Period	30 years		ATB2019
Interest Rate (real)	1.2%–3.5%	Varies by technology	ATB2019
Interest During Construction [nominal]	3.9%–8%	Varies by technology	ATB2019
Rate of Return on Equity (real)	2.45%–12.45%	Varies by technology	ATB2019
Debt Fraction (real)	40%-100%	Varies by technology	ATB2019
Tax Rate	25.%	Includes federal and state.	ATB2019
Present Value of Depreciation	0.5 – 0.8	Varies by technology	ATB2019
WACC (real)	Calculated using other assumptions		ATB2019

[69] Marissa Hummon, Paul Denholm, Jennie Jorgenson, David Palchak, Brendan Kirby, and Ookie Ma, *Fundamental Drivers of the Cost and Price of Operating Reserves* (NREL 2013), NREL/TP-6A20-58491, https://www.nrel.gov/docs/fy13osti/58491.pdf.

Appendix C. Data Sources for Production Cost Modeling (PCM)

The basic spatial properties of the PCM database are shared with the RPM data sets (shown in Table 23). Likewise, transmission network data (Table 26) is common between the two models, as is information about existing and new generators (Table 25, Table 27, and Table 28). Table 33 lists the time-series data used in the PCM. Table 34 discusses the assumptions for reserve provision used in PCM (see Table 31 for how the PCM assumptions compare with RPM modeling).

Table 33. Time-Series Data

Name	Information	Resolution	Source
Load	8,760 load profiles (MW) for each transmission node	Node, hour	dsgrid model (see Chapter 3 for explanation)
Wind output	MW	By plant, hourly	reV
PV output	MW	By plant, hourly	reV
Hydro fixed profiles	Fixed-dispatch hydro plant output by hour (MW)	By plant, hourly	LADWP or TEPPC
Hydro monthly energy limits	Dispatchable hydro energy availability by month and plant (GWh)	By plant, monthly	TEPPC
CSP solar availability	Inflow to the CSP plant from the solar field, to be dispatched optimally if combined with thermal storage (MW/MWh)	By plant, hourly	SAM[70]
DR availability	Determines the maximum amount of load that can change in any given hour (both up or down) and other constraints (MW/MWh)	By BA, by end use, hourly	dsgrid model (see Chapter 3 for explanation)

[70] "System Advisor Model (SAM)," NREL, https://sam.nrel.gov/.

Table 34. Summary of Reserve Modeling in PCM for All Years

Parameter	Assumption
Reserves enforced	Contingency spinning, contingency non-spinning regulation (upward and downward), flexibility (upward and downward)
Spatial resolution	By BA or reserve sharing group, hourly
Contingency requirement	Must be met in 10 minutes: contingency reserve requirements are the largest of 1) 738 MW, which is LADWP's entitlement to the maximum flow on one pole (i.e., one of two circuits, half the total capacity) of the STS tie between Intermountain Power Plant and Adelanto, or 2) LADWP's portion of the actual flow on the tie, which can reach 1428 MW. Requirement must be met with in-generation, except out-of-basin batteries in PV+battery installations, since they are distributed across a diverse set of lines and represent separate contingencies. This represents a more conservative approach than LADWP's current reserve policy, which is to hold reserves equal to the largest of 1) 738 MW (as above) or 2) LADWP's share of southward flow on the PDCI. Considering both poles of the STS as one contingency (i.e., a potential total failure of the system) rather than the failure of just one pole means that the reserve requirement in our modeling is as much as double what current LADWP policy would dictate.
Regulation reserves requirement	Must be met in five minutes: based on load and a statistical analysis of PV and wind forecast error (MW/MW-h). Detailed methodology is provided in a separate document.[71]
Flexibility reserves requirement	Must be met in 20 minutes: based on load and a statistical analysis of PV and wind forecast error (MW/MW-h). Detailed methodology is provided in a separate document.[72]
Renewable resource eligibility	Curtailed wind and solar can provide upward reserves

[71] Marissa Hummon, Paul Denholm, Jennie Jorgenson, and David Palchak, Brendan Kirby, and Ookie Ma, *Fundamental Drivers of the Cost and Price of Operating Reserves* (NREL, 2013), NREL/TP-6A20-58491, https://www.nrel.gov/docs/fy13osti/58491.pdf.
[72] Marissa Hummon, Paul Denholm, Jennie Jorgenson, and David Palchak, Brendan Kirby, and Ookie Ma, *Fundamental Drivers of the Cost and Price of Operating Reserves* (NREL, 2013), NREL/TP-6A20-58491, https://www.nrel.gov/docs/fy13osti/58491.pdf.

Table 35 lists generator-specific generator data sets. Data for existing units outside LADWP are derived from TEPPC, while LADWP units incorporate data from LADWP where possible. Data for new units are obtained from the RPM assumptions.

Table 35. PCM Generator Data

Parameter	Units	Generator Types Applicable	Information
Node	N/A	All	All generators require a connection to a node to determine their place in the transmission network
Fuel type	N/A	Thermal plants	Coal, gas, oil, uranium, biofuel, hydrogen
Reserve memberships	N/A	All	A switch to determine whether a generator may provide reserves
Maximum capacity	MW	All	Can vary by month for hydro, otherwise constant
Minimum generation level	MW	Thermal plants, hydro	
Heat rate	Btu/MWh	Thermal plants	Usually a curve with multiple points
Efficiency	%	Storage	
Variable O&M cost	$/MWh	Thermal plants, CSP	Variable O&M costs
Startup cost	$	Thermal plants, CSP	Cost incurred per generator startup
Min up/down	hour	Thermal plants, CSP	Number of hours a plant must be on or off, respectively, before changing its status
Max ramp up/down	MW/min	Thermal plants, CSP	
Forced outage rate	%	All	% of time generator is on unplanned outage
Mean time to repair	hour	All	Average amount of time taken to repair a generator that has been forced out
Maintenance rate	%	All	% of time generator is out for maintenance
Max energy month	MWh	Dispatchable hydro	Maximum amount of energy to be used over the course of the month, within max/min capacity constraints
Storage volume	MWh	Storage, CSP-TES, DR	

Table 36 lists miscellaneous data and constraints. Data for units outside LADWP is derived from TEPPC, with modifications to LADWP units incorporating data from LADWP.

Table 36. PCM System Data

Parameter	Units	Information
Fuel price	$/MMBtu	Varies by fuel type (i.e., coal, gas, oil, uranium, biomass) and often by region and month (especially coal and gas)
Emissions	lb/MMbtu	Lb of emissions released per MMBtu of each fuel type burned
Emissions cost	$/lb	Cost of each lb of emissions
Cost of unserved demand (violation of lost load)	$/MWh	Usually in the thousands of dollars, used to discourage dropping load
Cost of unserved reserves (violation of reserve shortage)	$/MWh	Less than VOLL above, but higher than the marginal cost of all generators by an order of magnitude
Other constraints	N/A	Other region or generator or BA-specific constraints that may impact operations, such as import constraints, local generation constraints, etc.

Appendix D. Data Sources for Power Flow and Stability

Power flow and stability analysis for the LA100 study used the GE PSLF software (version 21.0_06). Table 37 lists data items used by the PSLF model, starting with existing LADWP PSLF files obtained from LADWP.

Table 37. Data Requirements for Power Flow (PSLF) Modeling

Data	Source
Transmission network model, loads and generation	LADWP+RPM/PLEXOS: We use a base case suggested by LADWP (updated 2028 heavy summer case). It is modified based on generator additions and retirements, transmission builds, load increases, and new loads from RPM/PLEXOS outputs. We identified reactive power support devices (e.g., reactors, shunts, SVCs, and synchronous condensers) to be added or removed to maintain appropriate voltages and power factors in the power flow models. We assume that new RE-CTs have synchronous condenser capability.
List(s) of unplanned outages /contingencies	LADWP provided contingency files (.otg files). Some of these contingencies were modified to reflect changes in the LADWP network such as addition of new generators and/or addition of new lines.
Reliability criteria, including limits of various parameters such as voltages and thermal loadings	LADWP
Dynamic models and parameters used for generators, controllers, and HVDC	Starting point will be the models included in the .dyd file provided by LADWP. We modified this file by adding or removing dynamic models, changing MVA bases of generators, among other changes.
Remedial Action Schemes (RAS)	RAS action text files provided by LADWP. New RAS actions, such as due to the addition of generation in North, are also included in contingency analysis.

D.1 Detailed Approach and Assumptions for PSLF Modeling

The discussion below presents the general approach and assumptions for power flow and dynamic simulations. Any deviations from the approach and the assumptions are documented in Appendix E.

Generator Mapping:

- **LADWP**: Manual, nodal mapping between PSLF and PLEXOS. LADWP in PSLF includes Glendale and Burbank. However, in RPM/PLEXOS Glendale and Burbank are modeled as part of SCE. It is our understanding that there is uncertainty about the status of Grayson units. Therefore, we turned them off in both 2030 SB100 – High Load Stress and 2045 LA – Leads High Load scenarios, unless significant overloading on Rinaldi-Airway lines is observed in the pre-contingency or base cases, so that the worst impacts on LADWP's transmission network due to the absence of these units can be identified. Given the 2005 commissioning date of Burbank's Magnolia power plant, we will assume it to be present at

its full capacity in 2030 but assume it to be retired by 2045; this will also help us identify worst case transmission network loading in 2045. Here too, we will assume that the Magnolia plant is available for dispatch if significant pre-contingency overloads due to the removal of this plant are observed.
- **SCE, Nevada, and Arizona**: For each area, generators are nodally mapped to the extent possible or reasonable, and remaining generators were adjusted so that total synchronous and inverter-based generation is equal between PSLF and PLEXOS.
- **Northwest (BPA) and PACE**: Dispatch remains unchanged from the 2028 heavy summer case. But we made the proportion of generation between synchronous and non-synchronous generators same as it is in PLEXOS.
- **Other areas:** Same as in the 2028 heavy summer case.

Load Mapping:

- **LADWP**: Manual, nodal mapping between PSLF and PLEXOS. Allocated to load banks in proportion to 2028 heavy summer case to capture composite load models in dynamic data. Same power factor will be maintained at the load banks as in all-time peak condition. Glendale and Burbank load will be scaled by the ratio of LA Basin load in the analysis year to the LA Basin load in the 2028 heavy summer case.
- **SCE, Nevada, and Arizona**: Each area's load is scaled to match the total PLEXOS load.
- **Other areas:** Same as in the 2028 heavy summer case.

Distributed Generation Mapping:

- **LADWP**: Manual, nodal mapping between PSLF and PLEXOS.
- **SCE, Nevada, and Arizona**: Equally sized distributed generation units added at as many buses with composite load models as are necessary to accommodate total distributed generation in PLEXOS.
- **Other areas:** Same as in the 2028 heavy summer case.

Transmission Line Mapping:

- For any new transmission lines suggested by RPM (our capacity planning model), we added them in parallel to the existing lines such that the path followed by the line in PSLF is similar to that suggested by RPM.
- If only ratings were increased for existing lines, the new ratings were used for post processing of the contingency analysis results.

D.2 Power Flow Approach

We maintained the pre-contingency voltages close to 1 per unit on 230 kV and 138 kV lines and 1.06 per unit on the 500 kV lines in LADWP. Q_{max} and Q_{min} of new generators were also calculated assuming a power factor of 0.95 at rated real power.

We performed N-1, N-k (when more than one element is removed from service at the same time by a contingency), and N-1-1 steady-state contingency analyses. The contingency analysis was performed with post-contingency ratings set to rate 2 (emergency ratings).

We used the contingencies that LADWP provided us. The following list describes how we addressed new contingencies for the added generators and transmission lines:

Generator Contingencies (Power flow N-1 Contingencies)

1. RPM does not identify the size of an individual generator unit at a bus. Instead, it identifies the maximum generation capacity of various technologies that can be located at a bus. Therefore, to create a reasonably sized single contingency, we adopted this approach:
2. If the total generation dispatch at a bus is <=420 MW in PLEXOS, we aggregated all the units connected at the bus into a single unit. The aggregate unit was removed as a N-1 contingency.
3. If the total generation dispatch at a bus is >420 MW in PLEXOS, then we separated the entire generation at the bus into two units – a 420 MW unit and the second unit that is assigned the remaining generation. The 420 MW unit was removed as the N-1 contingency.
4. We selected the 420 MW value because it was the single largest unit dispatch in Area 26 in the 2028 heavy summer case.

Transmission Line Contingencies (power flow N-1 contingencies)

1. We modeled each new transmission line as a N-1 contingency.
2. We used the reliability criteria specified in the LADWP.cntl file that we received from LADWP.

Dynamic Analysis Approach Summary

1. For any new generator, we assumed 0.95 as the minimum power factor at rated power to calculate its MVA rating.
2. We modified the synchronous and non-synchronous MVA in LADWP, SCE, Nevada, and Arizona so that the total MVA of each area reflects the ratings of online generators in PLEXOS in these areas.
3. For any new synchronous generator that we added in LADWP, SCE, Nevada, and Arizona we selected the models and parameters of an existing plant in the dyd file provided by LADWP for the 2028 heavy summer case. We only changed the MVA of the selected model to match that of the generator being added.
4. We used regc_a, reec_c, and repc_a PSLF models to represent the dynamics of new inverter-based generators in LADWP, SCE, Nevada, Arizona, PACE, and Northwest.
5. All the “cmpldw” models in the 2028 case were replaced with the “cmpldwg” model to allow for distributed generation dynamics to be simulated.
6. We used the DER_A model (with default parameters in the PSLF manual) to model the dynamics of distributed generation units in Area 26 and we used the distributed generation PV model for SCE, Nevada, and Arizona.
7. We relied on the WECC_TPL.dycr file to identify dynamic simulation criteria violations. We followed TPL-001-WECC-CRT-3.1 to identify the buses that should be observed for voltage violations.

PSLF-Based Feasibility Evaluation of PLEXOS Dispatches Under Long Duration Outages

1. We used a combination of the following metrics to select the most constrained outage scenarios for PSLF feasibility evaluation: generator headroom, congestion cost, total production cost, in-basin imports, and shadow prices on voltage angles (from PLEXOS DC power flow model).

Appendix E. Additional PSLF Results

In this appendix, additional details are provided about the 2030 SB100 – Stress and 2045 Early & No Biofuels – High scenarios whose highest bus loading hours were modeled in PSLF. These details include discussion about the following topics:

- Creation of the power flow cases and the key parameters of these cases.
- Details about the flow violations that were summarized in the body of this chapter.
- Results from the transient contingency analysis that was performed to evaluate the ability of the LADWP system to achieve a stable and acceptable post contingency operating point.

E.1 Details of the Power Flow Base Cases

Creating the power flow cases was the first step in performing the steady-state and transient contingency analyses. The general approach and assumptions of creating the power flow cases has already been provided in Appendix D. In this section, we will focus on some deviations from the general approach that we had to make to create a solvable case. We also present a comparison of load and generation between the final PSLF cases and the corresponding PLEXOS load and generation dispatches.

For brevity, in the discussion that follows 2030 and 2045 will refer to the 2030 SB100 – Stress and 2045 Early & No Biofuels – High scenarios' highest bus loading hours, respectively. Similarly, the updated 2028 heavy summer case, which served as the starting point of the PSLF modeling will be referred to as the 2028 case. Table 38 presents the key deviations in the 2030 and 2045 cases from the general approach laid out in Appendix D.

Table 38. Deviations from the Power Flow Base Case Preparation Approach Presented in Appendix D

	2030	2045
Analysis Hour	**8/11/2030 09:00**	**8/11/2045 08:00**
Load Mapping in LADWP (PLEXOS to PSLF)	Glendale and Burbank load is not changed compared to the 2028 case. This was because the LA Basin load in 2030 reduced 1.3% compared to the 2028 case, which would have changed the 601 MW Glendale and Burbank load (excluding 111 MW of plant auxiliary load) by only 8 MW.	The LA Basin load increased to 7342 MW in 2045 compared to 6592 MW in the 2028 case. This represented an increase of 11%. The Glendale and Burbank load, however, was increased from 601 MW to 823 MW, which is an increase of 36%. In other words, we added about 153 MW of extra load.
Generation Mapping in LADWP (PLEXOS to PSLF)	Grayson units are dispatched at 236 MW compared to 119 MW in the 2028 case to resolve base case thermal violations in transmission circuits around Rinaldi. Dispatch from the Magnolia units in Burbank is reduced from 303 MW to 255 MW.	No change from the methodology of Appendix D

	2030	2045
Analysis Hour	**8/11/2030 09:00**	**8/11/2045 08:00**
ARIZONA, NEVADA, SCE	Because the power flow analysis was performed as a “round-trip” analysis (it means circular flow of data and information between RPM/PLEXOS and PSLF over multiple iterations) with RPM/PLEXOS over several cycles, the load and generation dispatch and proportion of synchronous and inverter-based generation in these areas was frozen after the RPM/PLEXOS results became reasonably stable. However, changes continued to be made in RPM/PLEXOS after this stage but because of time constraints we did not make further changes in PSLF in these areas unless changes were required to solve the case. Therefore, a large deviation in load and generation in these areas between PSLF and PLEXOS is possible. For these reasons, the MVAs of inverter-based and synchronous generators also did not accurately reflect the ratings of these generation technologies in PLEXOS.	Same argument as for 2030
Northwest (Area 40) and Utah	Proportion of inverter-based and synchronous generation in these areas was fixed as per the proportion in PLEXOS at the same stage when Load/Generation in ARIZONA, NEVADA, SCE was fixed as discussed above. However, deviation occurred in the later cycles to balance WECC-wide load and generation and to ensure an acceptable and stable power flow.	Same argument as 2030
Other WECC areas	Changes were made in their load and generation dispatch only to the extent necessary to balance WECC-wide load and generation and ensure an acceptable and stable power flow. For these reasons, the MVAs of inverter-based and synchronous generators also did not accurately reflect the ratings of these generation technologies in PLEXOS.	Same argument as 2030

Table 39 compares the generation dispatch in all areas of WECC among the 2028, 2030, and 2045 cases, while Table 40 compares the load in 2030 and 2045 between PSLF and PLEXOS.

Table 39. Bulk Generation in WECC Areas in 2028, 2030, and 2045

	2028 PSLF			2030 PLEXOS			2030 PSLF			2045 PLEOXS			2045 PSLF		
Area	IBR[a]	Sync.[a]	Total	IBR	Sync.	Total	IBR	Sync.	Total	IBR	Sync.	Total	IBR	Sync.	Total
ALBERTA	1,357	10,048	11,405	1,057	11,460	12,516	1,357	10,048	11,405	32	13,059	13,091	1,357	10,048	11,405
ARIZONA	1,189	22,712	23,901	2,186	16,292	18,478	5,589	16,701	22,290	4,691	3,893	8,584	6,556	19,251	25,807
B.C.HYDRO	27	12,109	12,136	28	8,988	9,016	27	12,110	12,137	421	5,973	6,394	27	12,110	12,137
EL PASO	72	1,477	1,549	640	2,057	2,696	72	1,477	1,549	1,931	407	2,338	72	1,477	1,549
FORTISBC	-61	1,172	1,111	0	0	0	-61	1,172	1,111	0	0	0	-61	1,172	1,111
IDAHO	166	2,353	2,519	4,335	1,416	5,751	166	2,355	2,521	10,379	356	10,735	166	2,355	2,521
IID	581	1,248	1,829	1,445	756	2,201	581	1,248	1,829	1,463	105	1,567	581	1,248	1,829
MEXICO-CFE	27	3,552	3,579	2	2,770	2,771	27	3,552	3,579	0	2,313	2,313	27	3,552	3,579
MONTANA	192	2,386	2,578	2,168	1,141	3,310	192	2,386	2,578	3,792	231	4,024	192	2,386	2,578
NEVADA	143	5,535	5,678	2,615	2,218	4,833	2,759	3,144	5,903	3,426	29	3,455	3,235	3,089	6,325
NEW MEXICO	317	2,600	2,916	775	1,104	1,878	317	2,600	2,916	3,548	345	3,892	317	2,600	2,916
NORTHWEST	865	34,336	35,201	6,900	16,281	23,181	10,156	22,232	32,388	17,045	5,328	22,374	16,054	16,014	32,068
PACE	1,537	10,453	11,990	1,462	7,466	8,928	3,607	8,383	11,990	1,444	1,247	2,691	5,912	6,078	11,990
PG AND E	1,662	22,658	24,319	12,263	6,034	18,297	1,688	23,024	24,712	16,682	1,514	18,196	1,701	23,193	24,894
PSCOLORADO	775	8,057	8,832	508	5,224	5,732	775	8,057	8,832	1,217	341	1,558	775	8,057	8,832
SANDIEGO	877	3,649	4,526	1,715	1,573	3,287	877	3,649	4,526	7,141	53	7,194	877	3,649	4,526
SIERRA	157	2,524	2,681	1,769	1,135	2,904	157	2,524	2,681	3,059	305	3,364	157	2,524	2,681
SOCALIF	4,941	13,020	17,960	5,622	9,214	14,836	6,855	9,666	16,521	7,059	352	7,411	7,261	10,664	17,925
WAPA L.C.	0	3,591	3,591	1,020	1,833	2,853	0	3,111	3,111	1,459	790	2,249	0	3,590	3,590
WAPA R.M.	139	6,421	6,560	166	3,912	4,078	139	6,421	6,560	6,111	797	6,908	139	6,421	6,560
WAPA U.W.	0	71	71	2,062	54	2,116	0	71	71	1,859	0	1,859	0	71	71
LADWP	2,381	4,686	7,067	3,795	3,084	6,879	3,810	3,600	7,410	4,394	3,182	7,576	4,361	3,186	7,547
Grand Total	17,343	174,657	192,000	52,533	104,012	156,541	39,090	147,513	186,602	97,153	40,620	137,773	49,706	142,742	192,448

[a] **IBR – Inverter-based Generation Resource; Sync. – Synchronous Generation**

Table 40. Load in WECC Areas in PLEXOS and PSLF in 2030 and 2045

Area	2030 PLEXOS (MW)	2030 PSLF (MW)	2030 Delta (MW; PSLF minus PLEXOS)	2045 PLEXOS (MW)	2045 PSLF (MW)	2045 Delta (MW; PSLF minus PLEXOS)
ALBERTA	13,572	11,363	-2,209	15,711	11,416	-4,295
ARIZONA	22,259	23,893	1,634	15,566	22,995	7,429
B.C. HYDRO	8,537	8,861	324	8,674	8,911	237
EL PASO	2,782	2,194	-588	3,267	2,204	-1,063
FORTISBC	-	797	797	-	801	801
IDAHO	5,054	4,298	-756	3,861	4,319	458
IID	1,236	1,467	231	830	1,475	645
MEXICO-CFE	2,963	3,486	523	2,722	3,505	783
MONTANA	2,071	2,139	68	1,760	2,151	391
NEVADA	6,254	7,211	957	3,758	7,533	3,775
NEW MEXICO	2,387	3,154	767	1,992	3,170	1,178
NORTHWEST	24,950	27,675	2,725	24,115	28,012	3,897
PACE	8,036	10,571	2,535	7,995	10,623	2,628
PG AND E	20,889	26,743	5,854	15,955	26,878	10,923
PSCOLORADO	6,485	8,744	2,259	4,734	8,788	4,054
SANDIEGO	4,899	4,340	-559	3,966	4,360	394
SIERRA	2,539	2,428	-111	2,502	2,441	-61
SOCALIF	19,136	20,827	1,691	13,607	20,863	7,256
WAPA L.C.	1,664	1,271	-393	2,101	1,278	-823
WAPA R.M.	5,451	5,853	402	7,441	5,885	-1,556
WAPA U.W.	198	-29	-227	173	(30)	-203
LADWP (in-basin)	6,540	6,507	-33	7,387	7,342	-45
LADWP (other)	-	-	0	-	-	0
Burbank & Glendale	-	601	601	-	823	823
LADWP Aux	-	231	231	-	175	175
LADWP Total	**6,540**	**7,339**	**799**	**7,387**	**8,340**	**953**
WECC Total	168,425	184,624	16,198	148,446	185,920	37,801

Overall, there is a very close match between the PLEXOS and PSLF synchronous and IBR generation in both 2030 and 2045 base cases, which allows us to accurately evaluate the reliability of the LADWP power system for the highest bus loading hour as designed by RPM and dispatched by PLEXOS. The differences in load and generation are almost exclusively because Glendale and Burbank are modeled in PLEXOS as external to LADWP, and plant auxiliary loads that are not modeled in PLEXOS (Table 39 and Table 40).

There are significant differences between the load and generation of other WECC areas because of the focus of this project on LADWP. Other reasons for these differences are discussed in Table 38.

Some key parameters of the PSLF cases are shown in Table 41. Reactive power parameters in the 2028, 2030, and 2045 PSLF base cases are summarized in Table 42. The real and reactive power imports in the 2028, 2030, and 2045 cases are shown in Table 43.

Table 41. Key Parameters of the 2028, 2030, and 2045 PSLF Base Cases

Parameter	2028	2030	2045
Load (MW)	7,550	7,339	8,340
Losses (includes PDCI and IPPDC losses; MW)	394	190	305
Total Real Power Demand (including losses; MW)	7,944	7,529	8,645
Bulk Generation (MW)	7,050	7,410	7,547
Distributed Generation (MW)	0	-741	-619
Imports (MW)	895	860	1,717
Total Real Power Generation (MW)	7,945	7,529	8,645
Total Online MVA	12,318	10,195	14,065
Online Synchronous MVA (including contribution from synchronous condensers)	8,888	4,299	4,138
Total Kinetic Energy Stored in Synchronous Machines at steady-state (MW-seconds)	21,000	15,990	16,965

Table 42. Reactive Powers Comparison between the 2028, 2030, and 2045 PSLF Base Cases

	2028	2030	2045
Load (Mvar)	1,759	1,786	1,726
Losses (Mvar)	3,226	1,787	3,675
Total Reactive Power Demand (including losses; Mvar)	4,985	3,573	5,401
Bulk Generation (Mvar)	1,813	135	-487
Distributed Generation (Mvar)	0	0	0
Shunt Capacitors (Mvar)	3,358	4,411	7,364
Imports (Mvar)	-193	-999	-1,484
Total Reactive Power Generation (Mvar)	**4,978**	**3,547**	**5,393**

Table 43. Imports into LADWP in 2028, 2030, and 2045 PSLF Cases

From Area	To Area	Real Power (MW)			Reactive Power (Mvar)		
LADWP		2028	2030	2045	2028	2030	2045
	ARIZONA	104	-167	154	-172	-176	-183
	NEVADA	-305	-169	-140	32	-36	-6
	WAPA L.C.	546	-70	256	3	-42	-14
	SOCALIF	-2118	1043	1193	-15	-762	-1051
	NORTHWEST	2240	31	202	0	0	0
	SIERRA	36	-5	-8	-14	-28	-42
	PACE	391	197	60	-27	45	-187
	Total	894	860	1717	-193	-999	-1484

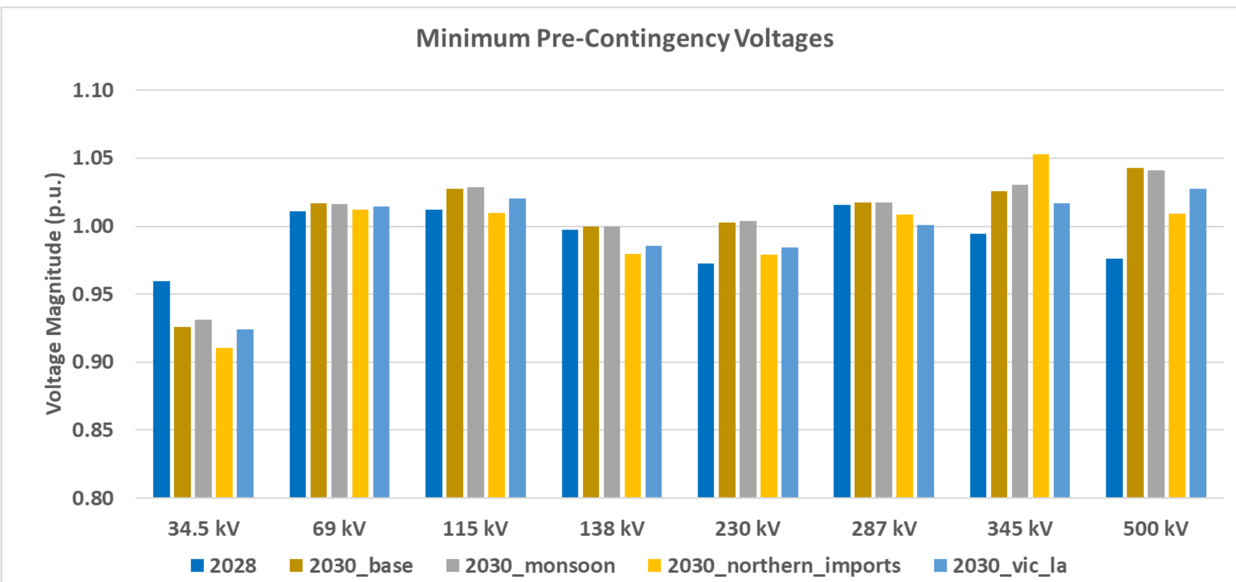
Positive means LADWP is importing.

Table 41, Table 42, and Table 43 show that, in terms of real and reactive power demands and imports, the 2030 case may appear less stressed than the 2028 case due to lower load, higher generation, and lower imports in the 2030 case. However, it is the generation location in LADWP that stresses the 2030 case more compared to the 2028 case, which is reflected in the increased thermal violations that were summarized in the body of this chapter. This can be seen from increased Eastern imports that are shown in Figure 75. The Northern imports in Figure 74 are lower than those in the 2028 case, but it is important to note that the Northern imports in the 2030 base case do not include any generation from Castaic whereas 2028 Northern imports include 900 MW from Castaic. This implies that a lot of Northern imports in the 2030 base case are coming from the region around Barren Ridge and Cottonwood, which has weaker transmission system and causes the 2030 base case to become more stressed than the 2028 case.

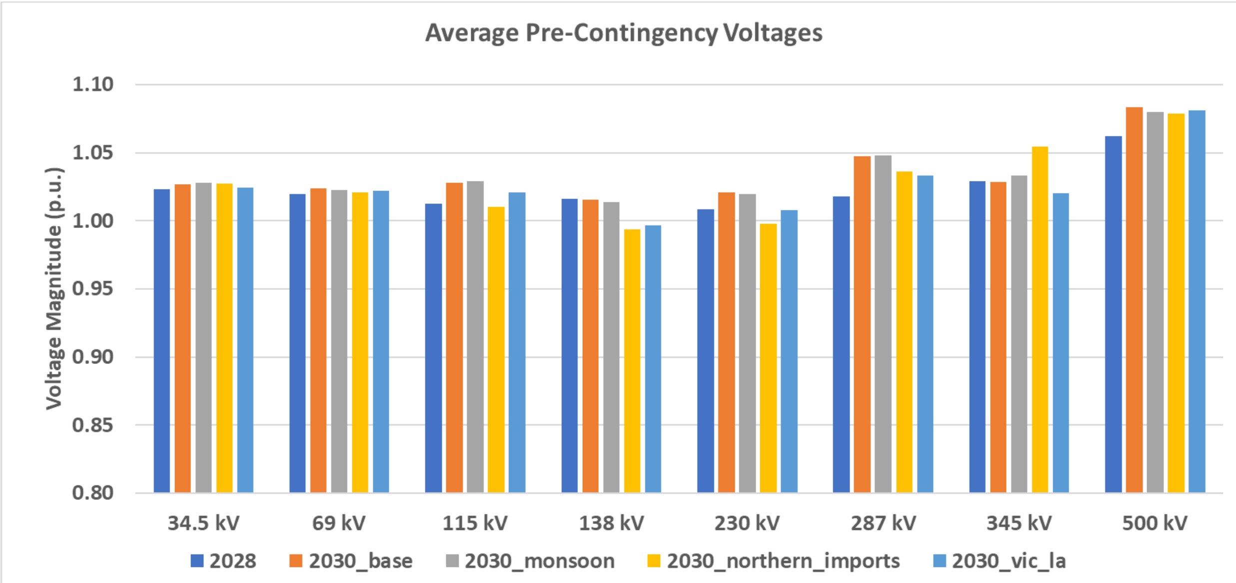
Table 41 and Table 42 show that the 2045 case is more stressed than the 2028 case as the real power demand increased by around 700 MW while the reactive power demand went up by around 400 Mvar. We did not attempt to optimize the amount of reactive power support that was needed to serve the demand in the 2030 and 2045 cases. This can be seen from Table 41, Table 42, and Table 43 where added shunt capacitors result in quite a bit more reactive power being generated resulting in lower reactive power demand from bulk generators and significantly more reactive power exports from LADWP.

The stored kinetic energy in synchronous machines decreased substantially in both 2030 and 2045 cases but was still quite high because of the geothermal and hydrogen combustion turbines that were interfaced with the grid via synchronous machines. The amount of online synchronous generation MVA almost halved in both 2030 and 2045 cases compared to the 2028 case. This data can be seen in Table 41.

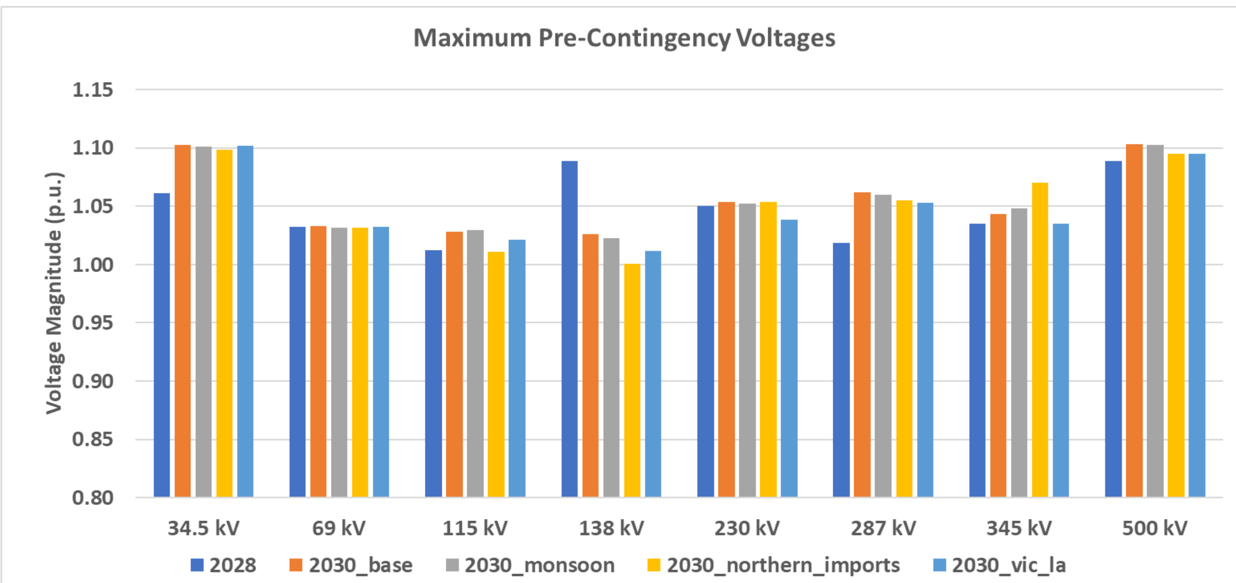
Bus voltage statistics in LADWP are shown in Figure 70 and Figure 71. These figures show that enough reactive power support was provided in the 2030 and 2045 cases to keep the voltages at various voltage levels very close to or above those found in the 2028 case, while still maintaining them at less than 1.1 p.u. Even in the sensitivity cases, pre-contingency voltages are comparable to those found in the base cases in both 2030 and 2045. The discussion on creating the sensitivity cases is provided next.



(a)

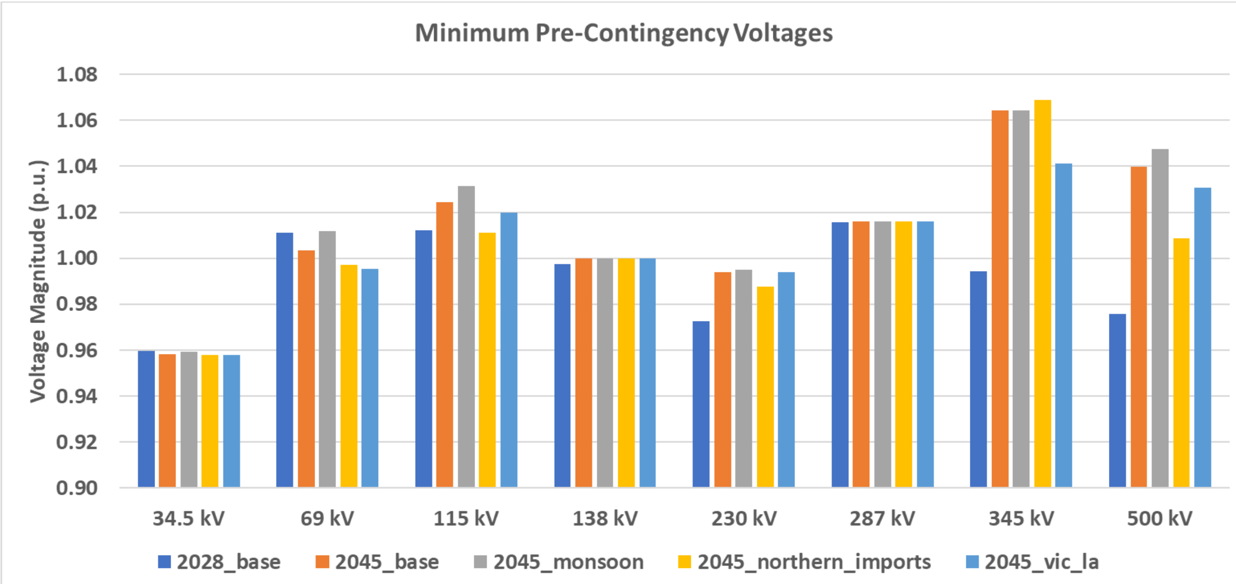


(b)



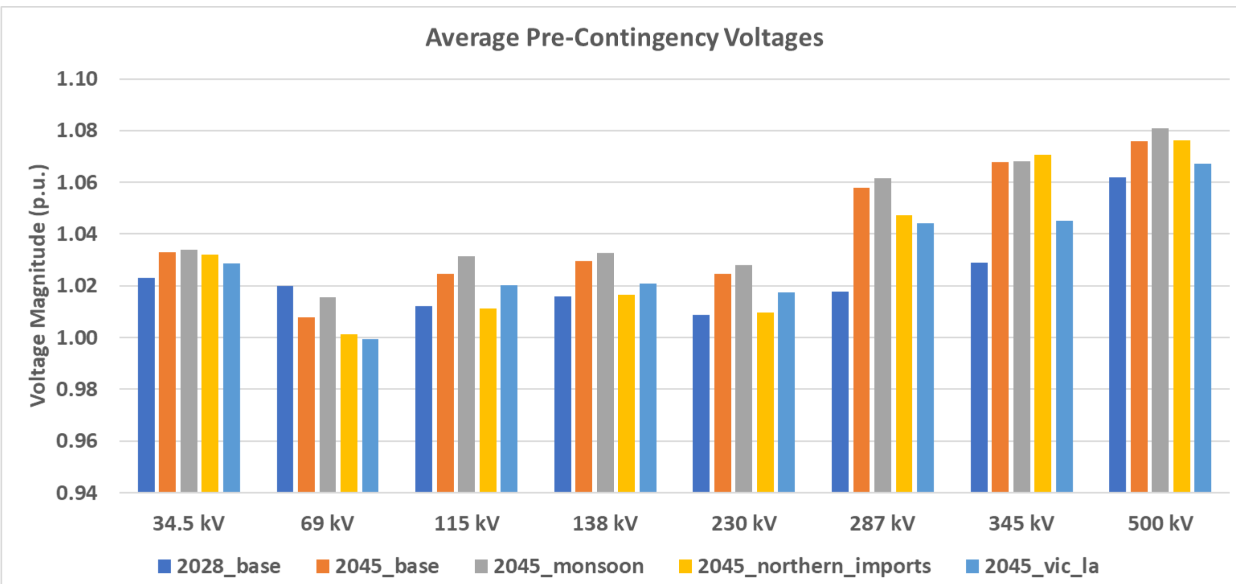
(c)

Figure 70. Pre-contingency minimum, average, and maximum bus voltages in LADWP in the 2028 and 2030 PSLF Base and Sensitivity Cases: (a) minimum voltage magnitudes, (b) average voltage magnitudes, and (c) maximum voltage magnitudes



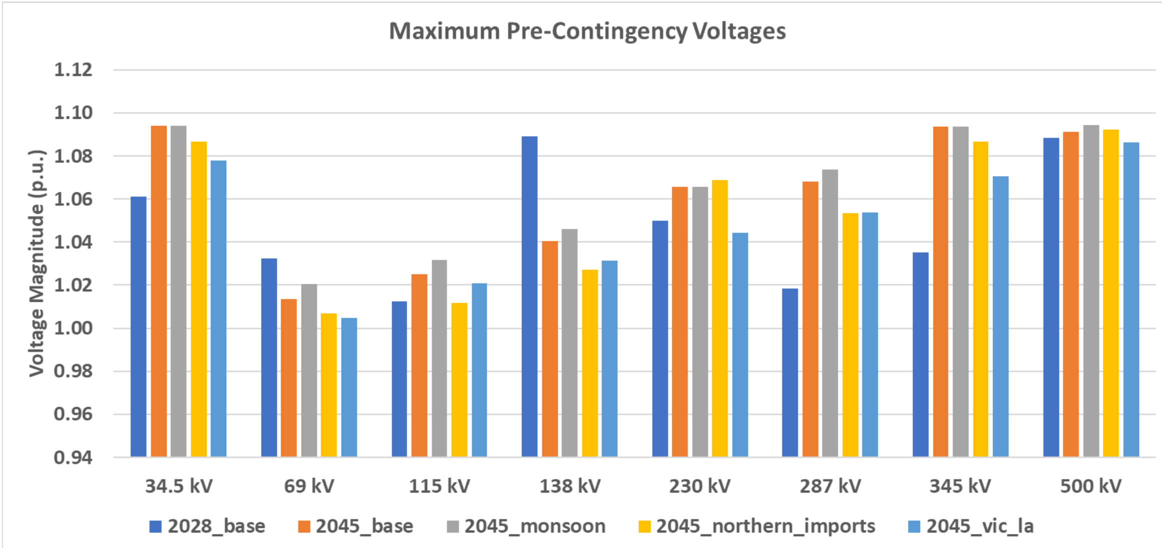
Minimum Pre-Contingency Voltages
Voltage Magnitude (p.u.)
1.08
1.06
1.04
1.02
1.00
0.98
0.96
0.94
0.92
0.90
34.5 kV
69 kV
115 kV
138 kV
230 kV
287 kV
345 kV
500 kV
2028_base
2045_base
2045_monsoon
2045_northern_imports
2045_vic_la

(a)



Average Pre-Contingency Voltages
Voltage Magnitude (p.u.)
1.10
1.08
1.06
1.04
1.02
1.00
0.98
0.96
0.94
34.5 kV
69 kV
115 kV
138 kV
230 kV
287 kV
345 kV
500 kV
2028_base
2045_base
2045_monsoon
2045_northern_imports
2045_vic_la

(b)



(c)

Figure 71. Pre-contingency minimum, average, and maximum bus voltages in LADWP in the 2028 and 2045 PSLF Base and Sensitivity Cases: (a) minimum voltage magnitudes, (b) average voltage magnitudes, and (c) maximum voltage magnitudes

E.2 Details of the Power Flow Sensitivity Cases

We created three sensitivity cases and performed steady-state contingency analysis on these. The procedure for creating the sensitivity cases is discussed next.

Monsoon Sensitivity

The objective of the monsoon sensitivity was to evaluate system reliability under hot, humid and overcast conditions that may simultaneously occur in Los Angeles and other nearby areas. To implement such a scenario, we decided to adopt the following approach:

- Make real power dispatch of all solar plants in the entire LADWP balancing authority zero.
- There were several PV+Battery and battery-only plants that were modeled in the base case. We assumed that while the PV portion of these plants would dispatch at zero, the batteries will dispatch at their ratings, which were assumed to be 33% of the total plant's rating.[73] All the battery-only plants were charging in the base case. These plants were kept unchanged.
- Distributed PV was also made zero and distributed storage was maximized to compensate for the loss of distributed PV.
- Any further generation increase required to balance load and generation was obtained from LADWP's synchronous generation resources available inside the LA Basin and outside the basin in that order.

Based on this approach we made the changes given in Table 44 in 2030 and 2045.[74] The pre-contingency bus voltage statistics for this sensitivity are shown in Figure 70 and Figure 71 above.

[73] The ratings of the Battery portion of a PV+Battery plant varied over a wide range in RPM. 33% was the smallest value in this range and this value was chosen to stress the system.

[74] Ideally, reduction and increase in generation should be identical in all the sensitivities. However, some difference can be seen in the amount of generation increase and decrease. These differences are small except in 2045 monsoon

Table 44. Changes in Real Power Generation to Create the 2030 and 2045 Monsoon Sensitivity Cases

Generation Location	2030 (MW)	2045 (MW)
Barren Ridge	-675	-674
Victorville	-495	-251
Marketplace	-326	-253
Rosamond	-262	-589
Hill Tap	-247	-
Crystal	-208	-203
Beacon Solar	-48	9
North Ridge	-38	-
Toluca	-32	-
Tarzana	-29	-
Rinaldi	-22	-21
Distributed Generation	-268	55
Velasco	-	-39
Airport	-	-37
Fairfax	-	-18
Century	-	-26
Cottonwood	48	-159
Total Reduction	2601	2205
PP2G1	2	-
PP1G1A	2	-
Scattergood	113	-
Valley	259	456
Haynes	260	-
Intermountain	320	432
Harbor	356	236
Castaic	1250	1250
Total Increase	**2562**	**2372**

sensitivity where the increase in generation is 170 MW more than the reduction in generation. The increased LA Basin generation could have reduced the line loadings in 2045 monsoon sensitivity; however, it is unlikely that any violation would have been eliminated. For this reason, this error is unlikely to materially change the contingency analysis results presented in this appendix and in the main chapter earlier.

Northern Imports Sensitivity

The main objective of this sensitivity was to stress the transmission system that brings power into the LA Basin from the North. To do so, we made the changes given in Table 45 in 2030 and 2045. The pre-contingency bus voltage statistics for this sensitivity are shown in Figure 70 and Figure 71 above.

Table 45. Changes in Real Power Generation to Create the 2030 and 2045 Northern Imports Sensitivity Cases

Generation Location	2030 (MW)	2045 (MW)
Intermountain	-1,025	-1,434
Haynes	-750	-772
Valley	-606	-
Scattergood	-599	-
Harbor	-155	-468
Total Reduction	-3,135	-2,674
Barren Ridge	177	-
Cottonwood	254	-
Castaic	1,250	1,250
PDCI at Sylmar (LADWP)	1,414	1,414
Total Increase	**3,095**	**2,664**

VIC-LA Sensitivity

The objective of the VIC-LA sensitivity was to evaluate system reliability when 4,300 MW is forced to flow over the VIC-LA path. This sensitivity evaluated the ability of the LADWP's transmission system to import power from the east (Arizona [e.g., Gila River], Nevada, and WAPA L.C.). The intention was to increase generation from remote resources east of LADWP. The VIC-LA path comprises of the elements listed in Table 46.

Table 46. VIC-LA Path Elements

From Bus	To Bus	Circuit	kV	Measurement Bus	2028 (MW)	2030 Base (MW)	2045 Base (MW)
VICTORVL	RINALDI	1	500	VICTORVL	468	650	926
ADELANTO	RINALDI2	1	500	ADELANTO	513	699	983
ADELANTO	TOLUCA	1	500	ADELANTO	906	1122	1536
VIC13-16	CNTURY1	1	500	VIC13-16	200	314	345
VIC18-15	CNTURY2	1	500	VIC18-15	194	305	334
Total					2281	3090	4124

The following approach was followed to stress the VIC-LA path:

- Maximize the flow on IPPDC, up to 2,400 MW if there is enough generation at Intermountain and reduce the LA Basin generation by the same amount.
- If the VIC-LA flow does not reach 4,300 in step 1, further reduce LA Basin generation and increase generation in Arizona to increase the VIC-LA flow to 4,300 MW.

Generation changes implemented to achieve the 4,300 MW VIC-LA flow are shown in Table 47. The pre-contingency bus voltage statistics for this sensitivity are shown in Figure 70 and Figure 71 above.

Table 47. Changes in Real Power Generation to Create the 2030 and 2045 VIC-LA Sensitivity Cases

Generation Location	2030 (MW)	2045 (MW)
Harbor	-322	-
Haynes	-750	-229
Scattergood	-599	-
Total Reduction	1,671	229
Intermountain	921	228
Arizona (APS)	741	-
Total Increase	1,662	228

Imports from North and East (VIC-LA path flow) into the LA Basin were also calculated for the 2028, 2030, and 2045 cases. The elements that were considered in the Eastern imports are listed in Table 48. The bar charts of Northern and Eastern imports for the 2028, 2030, and 2045 cases are shown in Figure 72, Figure 73, Figure 74, and Figure 75.

Table 48. Elements Considered in Northern Imports

From Bus Number	From Bus Name	From Bus kV	To Bus Number	To Bus Name	To Bus kV	Ckt
26135	HSKLLCYN	230	26052	OLIVE	230	1
26135	HSKLLCYN	230	26061	RINALDI	230	1
26135	HSKLLCYN	230	26094	SYLMARLA	230	1
26135	HSKLLCYN	230	26094	SYLMARLA	230	2
26010	CASTAIC34	230	26086	NRTHRDGE	230	1
26099	SYLMAR2	230	26094	SYLMARLA	230	1
26097	SYLMAR1	230	24147	SYLMAR S	230	1
24114	PARDEE	230	24147	SYLMAR S	230	1
24114	PARDEE	230	24147	SYLMAR S	230	2
24036	EAGLROCK	230	24147	SYLMAR S	230	1
24059	GOULD	230	24147	SYLMAR S	230	1

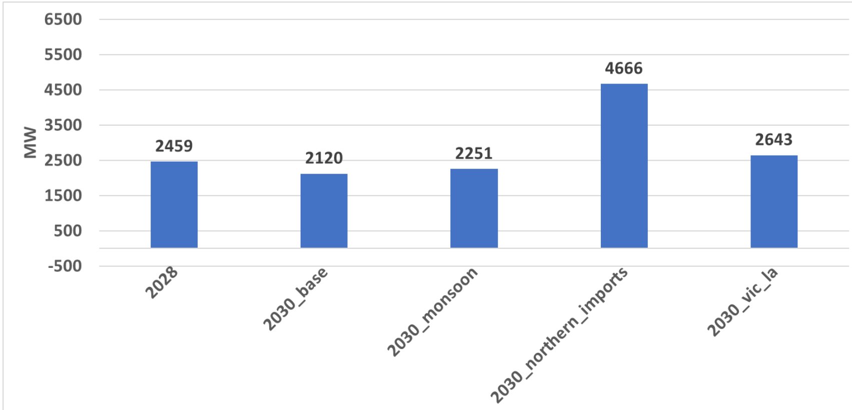


Figure 72. Comparison of northern imports in 2028 and 2030 Base and Sensitivity cases

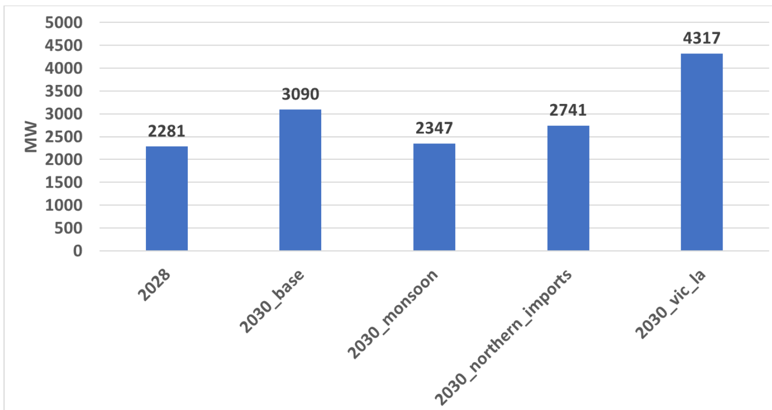


Figure 73. Comparison of eastern imports (VIC-LA) in 2028 and 2030 Base and Sensitivity cases

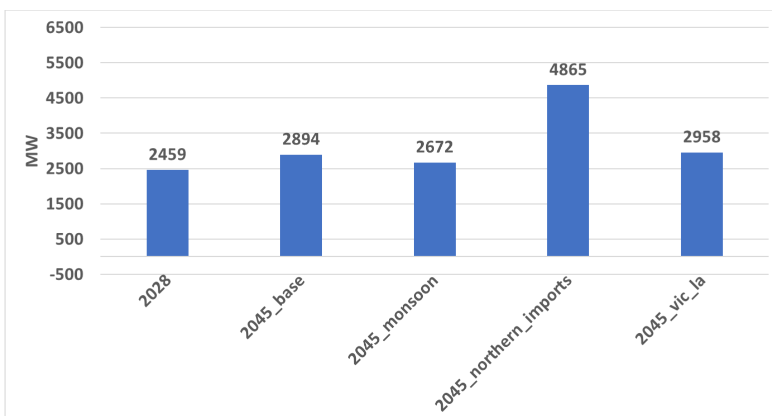


Figure 74. Comparison of northern imports in 2028 and 2045 Base and Sensitivity cases

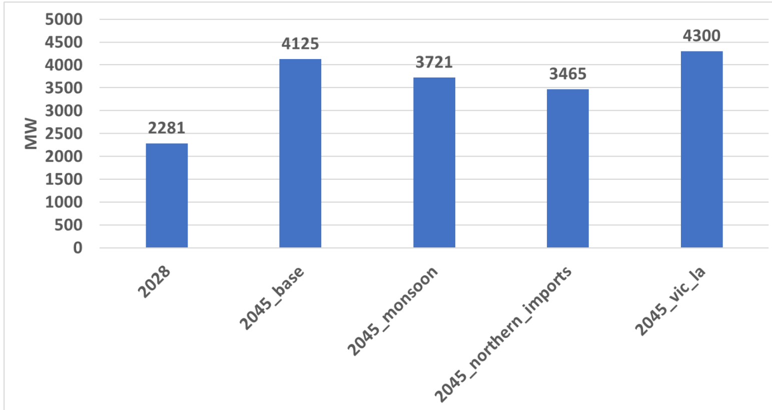


Figure 75. Comparison of eastern imports (VIC-LA) in 2028 and 2045 Base and Sensitivity cases

The Northern and Eastern imports provide key insights on the results that may be expected in contingency analysis. These are:

- The 2030 base case has 300 MW less Northern imports but 800 MW higher Eastern imports compared to the 2028 case. However, in the 2030 base case the bulk of the Northern imports (1,500 MW) are because of the generation added at Barren Ridge, Cottonwood, and Rosamond buses, whereas in the 2028 case imports from this region were around 1,000 MW. In other words, weak northern transmission system must support more flows in the 2030 base case compared to the 2028 case. Coupled with more eastern imports into the LA Basin, the 2030 base case is expected to be more stressed than the 2028 case. This was reflected in several thermal violations in the 2030 base case during contingency analysis that were summarized in the body of this chapter.
- On the other hand, the 2030 monsoon sensitivity flows from both north and east are almost the same or lower than the flows in the 2030 base case (because of increased dispatch from generators in the basin as seen in Table 44). This is the likely reason for few more severe or new thermal violations in the 2030 monsoon sensitivity compared to the 2030 base case.
- The Northern imports sensitivity resulted in more than 200% increase in Northern imports. This explains the large number of more severe and new thermal violations in this sensitivity compared to the 2030 base case.
- The VIC-LA sensitivity also sees a large jump in the VIC-LA path flow (by 1,200 MW), which explains the large number of more severe and new thermal violations in this sensitivity compared to the 2030 base case.
- The imports in the 2045 cases are considerably higher when compared with the corresponding 2030 cases: 200–800 MW higher Northern imports and 700–1400 MW higher Eastern imports except for the VIC-LA sensitivity. As a result, several lines and transformers see more severe thermal violations than those observed in all the 2030 cases and some new thermal violations are also found that were not observed in the 2030 cases.

In summary, high Northern and Eastern imports into the LA Basin in 2030 and 2045 compared to the 2028 case arising out of larger loads and reduced LA Basin generation dispatch are the primary drivers for thermal violations observed during steady-state contingency analysis.

E.3 Steady-State Contingency Analysis Results (Thermal Violations)

The detailed tables of lines and transformers thermal violations that were summarized in the body of this chapter are provided in this section.

2030 Base Case

Table 49. Thermal Violations in 2030 Base Case

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	N-1	N-k	N-1-1	Max of N-1, N-k, and N-1-1 Loadings
26065	SCATERGD	138	26089	AIRPORT	138	1	Line	145%	148%	169%	169%
26065	SCATERGD	138	26089	AIRPORT	138	2	Line	145%	148%	169%	169%
26061	RINALDI	230	26013	AIRWAY	230	1	Line	-	115%	159%	159%
26061	RINALDI	230	26013	AIRWAY	230	2	Line	-	108%	156%	156%
26076	FAIRFAX	138	26088	OLYMPCLD	138	A	Line	-	115%	141%	141%
26076	FAIRFAX	138	26088	OLYMPCLD	138	B	Line	-	115%	141%	141%
26013	AIRWAY	230	26081	ATWATER	230	1	Line	-	-	135%	135%
26013	AIRWAY	230	26081	ATWATER	230	2	Line	-	-	135%	135%
26268	TOL E	230	26082	HOLYWD_E	230	1	Line	129%	127%	-	129%
26080	VELASCO	230	26081	ATWATER	230	1	Line	-	109%	128%	128%
26083	HOLYWD1	138	26085	HOLYWDLD	138	1	Line	-	126%	-	126%
26084	HOLYWD2	138	26085	HOLYWDLD	138	1	Line	-	126%	-	126%
26093	TARZANA	230	26087	OLYMPC	230	3	Line	-	124%	124%	124%
26268	TOL E	230	26081	ATWATER	230	1	Line	-	118%	118%	118%
26068	STJOHN	230	26081	ATWATER	230	1	Line	-	109%	118%	118%
26063	RIVER	230	26080	VELASCO	230	1	Line	-	116%	118%	118%
26103	VALLEY	230	26078	TOLUCA	230	1	Line	-	-	116%	116%
26103	VALLEY	230	26268	TOL E	230	2	Line	-	-	116%	116%
26093	TARZANA	230	26087	OLYMPC	230	1	Line	-	115%	115%	115%
26093	TARZANA	230	26087	OLYMPC	230	2	Line	-	115%	115%	115%
26076	FAIRFAX	138	26014	GRAMERC1	138	1	Line	-	112%	-	112%
26076	FAIRFAX	138	26014	GRAMERC1	138	2	Line	-	112%	-	112%

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	N-1	N-k	N-1-1	Max of N-1, N-k, and N-1-1 Loadings
26061	RINALDI	230	26103	VALLEY	230	1	Line	-	-	109%	109%
26061	RINALDI	230	26103	VALLEY	230	2	Line	-	-	109%	109%
26061	RINALDI	230	26094	SYLMARLA	230	4	Line	-	108%	-	108%
26076	FAIRFAX	138	26083	HOLYWD1	138	A	Line	-	104%	-	104%
26076	FAIRFAX	138	26084	HOLYWD2	138	B	Line	-	104%	-	104%
26070	CNTURY1	287	26267	VIC13-16	287	1	Line	-	-	104%	104%
26071	CNTURY2	287	26265	VIC18-15	287	1	Line	-	-	102%	102%
26086	NRTHRDGE	230	26093	TARZANA	230	1	Line	-	100%	100%	100%
26088	OLYMPCLD	138	26087	OLYMPC	230	E	Tran	112%	-	143%	143%
26088	OLYMPCLD	138	26087	OLYMPC	230	F	Tran	111%	-	143%	143%
26094	SYLMARLA	230	24147	SYLMAR S	230	F	Tran	-	115%	115%	115%
26094	SYLMARLA	230	24147	SYLMAR S	230	E	Tran	-	115%	115%	115%
26069	CNTURY	138	26072	CNTURYLD	230	E	Tran	-	-	108%	108%
26069	CNTURY	138	26072	CNTURYLD	230	H	Tran	-	-	108%	108%
26085	HOLYWDLD	138	26182	HOLYWD_F	230	F	Tran	102%	-	-	102%
26262	SCA PS	138	26066	SCATERGD	230	E	Tran	-	101%	101%	101%
26065	SCATERGD	138	26262	SCA PS	138	E	Tran	-	101%	101%	101%

2030 Monsoon Sensitivity

Table 50. Lines/Transformers with Higher Magnitude of Thermal Violations in 2030 Monsoon Sensitivity Compared to the 2030 Base Case

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	N-1	N-k	% increase (max of N-1 and N-k wr.t to max of 2030 base case in Table 49
26076	FAIRFAX	138	26014	GRAMERC1	138	1	Line	-	115%	3.38%
26076	FAIRFAX	138	26014	GRAMERC1	138	2	Line	-	115%	3.38%
26268	TOL E	230	26082	HOLYWD_E	230	1	Line	131%	128%	1.00%
26085	HOLYWDLD	138	26182	HOLYWD_F	230	F	Tran	103%	101%	0.75%
26262	SCA PS	138	26066	SCATERGD	230	E	Tran	-	101%	0.20%
26065	SCATERGD	138	26262	SCA PS	138	E	Tran	-	101%	0.19%

Table 51. New Thermal Violations in 2030 Monsoon Sensitivity Compared to the 2030 Base Case

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	N-1	N-k
26073	WLMNTN	138	26091	HARBOR	138	D	Line	134%	234%
26010	CASTAIC34	230	26086	NRTHRDGE	230	1	Line	-	178%
26069	CNTURY	138	26073	WLMNTN	138	1	Line	-	112%
26069	CNTURY	138	26073	WLMNTN	138	2	Line	-	112%
26091	HARBOR	138	26096	TAP 2	138	1	Line	-	104%
26091	HARBOR	138	26095	TAP 1	138	1	Line	-	102%

2030 Northern Imports Sensitivity

Table 52. Lines/Transformers with Higher Magnitude of Thermal Violations in 2030 Northern Imports Sensitivity Compared to the 2030 Base Case

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	N-1	N-k	% increase (max of N-1 and N-k wr.t to max of 2030 base case in Table)
26093	TARZANA	230	26087	OLYMPC	230	1	Line	133%	242%	111%
26093	TARZANA	230	26087	OLYMPC	230	2	Line	133%	242%	111%
26093	TARZANA	230	26087	OLYMPC	230	3	Line	138%	259%	110%
26061	RINALDI	230	26094	SYLMARLA	230	4	Line	108%	217%	100%
26086	NRTHRDGE	230	26093	TARZANA	230	1	Line	112%	166%	66%
26080	VELASCO	230	26081	ATWATER	230	1	Line	164%	202%	58%
26063	RIVER	230	26080	VELASCO	230	1	Line	129%	160%	36%
26068	STJOHN	230	26081	ATWATER	230	1	Line	154%	141%	30%
26083	HOLYWD1	138	26085	HOLYWDLD	138	1	Line	-	150%	19%
26084	HOLYWD2	138	26085	HOLYWDLD	138	1	Line	-	150%	19%
26076	FAIRFAX	138	26083	HOLYWD1	138	A	Line	-	124%	19%
26076	FAIRFAX	138	26084	HOLYWD2	138	B	Line	-	124%	19%
26268	TOL E	230	26082	HOLYWD_E	230	1	Line	136%	142%	10%
26013	AIRWAY	230	26081	ATWATER	230	1	Line	145%	123%	8%
26013	AIRWAY	230	26081	ATWATER	230	2	Line	145%	123%	8%
26061	RINALDI	230	26013	AIRWAY	230	1	Line	155%	168%	6%
26061	RINALDI	230	26103	VALLEY	230	2	Line	115%	115%	5%
26061	RINALDI	230	26103	VALLEY	230	1	Line	115%	102%	5%
26076	FAIRFAX	138	26014	GRAMERC1	138	1	Line	-	115%	3%
26076	FAIRFAX	138	26014	GRAMERC1	138	2	Line	-	115%	3%
26061	RINALDI	230	26013	AIRWAY	230	2	Line	148%	157%	1%
26071	CNTURY2	287	26265	VIC18-15	287	1	Line	-	103%	1%
26094	SYLMARLA	230	24147	SYLMAR S	230	E	Tran	-	189%	64.82%

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	N-1	N-k	% increase (max of N-1 and N-k wr.t to max of 2030 base case in Table)
26094	SYLMARLA	230	24147	SYLMAR S	230	F	Tran	100%	189%	64.76%
26065	SCATERGD	138	26262	SCA PS	138	E	Tran	-	116%	14.35%
26262	SCA PS	138	26066	SCATERGD	230	E	Tran	-	116%	14.34%
26085	HOLYWDLD	138	26182	HOLYWD_F	230	F	Tran	104%	101%	2.05%

Table 53. New Thermal Violations in 2030 Northern Imports Sensitivity Compared to the 2030 Base Case

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	N-1	N-k
26136	COTTONWD	230	26132	BARRENRD	230	1	Line	153%	153%
26061	RINALDI	230	26094	SYLMARLA	230	1	Line	120%	123%
26061	RINALDI	230	26094	SYLMARLA	230	3	Line	117%	120%
26135	HSKLLCYN	230	26094	SYLMARLA	230	1	Line	-	111%
26135	HSKLLCYN	230	26094	SYLMARLA	230	2	Line	-	107%
26068	STJOHN	230	26063	RIVER	230	1	Line	101%	-
26135	HSKLLCYN	230	26061	RINALDI	230	1	Line	-	101%
26085	HOLYWDLD	138	26082	HOLYWD_E	230	E	Tran	100%	-

2030 VIC-LA Sensitivity

Table 54. Lines/Transformers with Higher Magnitude of Thermal Violations in 2030 VIC-LA Sensitivity Compared to the 2030 Base Case

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	N-1	N-k	% increase (max of N-1 and N-k wr.t to max of 2030 base case in Table 49)
26093	TARZANA	230	26087	OLYMPC	230	3	Line	128%	240%	94%
26093	TARZANA	230	26087	OLYMPC	230	1	Line	123%	224%	94%
26093	TARZANA	230	26087	OLYMPC	230	2	Line	123%	224%	94%
26080	VELASCO	230	26081	ATWATER	230	1	Line	168%	207%	62%
26086	NRTHRDGE	230	26093	TARZANA	230	1	Line	-	153%	53%
26063	RIVER	230	26080	VELASCO	230	1	Line	128%	161%	36%
26068	STJOHN	230	26081	ATWATER	230	1	Line	156%	142%	32%
26061	RINALDI	230	26094	SYLMARLA	230	4	Line	-	134%	24%
26083	HOLYWD1	138	26085	HOLYWDLD	138	1	Line	-	151%	20%
26084	HOLYWD2	138	26085	HOLYWDLD	138	1	Line	-	151%	20%
26076	FAIRFAX	138	26083	HOLYWD1	138	A	Line	-	125%	20%
26076	FAIRFAX	138	26084	HOLYWD2	138	B	Line	-	125%	20%
26268	TOL E	230	26082	HOLYWD_E	230	1	Line	146%	140%	13%
26070	CNTURY1	287	26267	VIC13-16	287	1	Line	115%	114%	10%
26071	CNTURY2	287	26265	VIC18-15	287	1	Line	112%	112%	10%
26268	TOL E	230	26081	ATWATER	230	1	Line	114%	119%	0%
26094	SYLMARLA	230	24147	SYLMAR S	230	E	Tran	-	159%	38.84%
26094	SYLMARLA	230	24147	SYLMAR S	230	F	Tran	-	160%	38.77%
26262	SCA PS	138	26066	SCATERGD	230	E	Tran	-	111%	10.04%
26065	SCATERGD	138	26262	SCA PS	138	E	Tran	-	111%	10.04%
26085	HOLYWDLD	138	26182	HOLYWD_F	230	F	Tran	112%	105%	10.03%

Table 55. New Thermal Violations in 2030 VIC-LA Sensitivity Compared to the 2030 Base Case

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	N-1	N-k
26073	WLMNTN	138	26091	HARBOR	138	D	Line	-	137%
26069	CNTURY	138	26073	WLMNTN	138	1	Line	-	111%
26069	CNTURY	138	26073	WLMNTN	138	2	Line	-	111%
26094	SYLMARLA	230	26086	NRTHRDGE	230	1	Line	-	109%
26078	TOLUCA	230	26268	TOL E	230	1	Line	108%	103%
26068	STJOHN	230	26063	RIVER	230	1	Line	108%	101%
26085	HOLYWDLD	138	26082	HOLYWD_E	230	E	Tran	106%	105%
26070	CNTURY1	287	26069	CNTURY	138	F	Tran	104%	-

Table 56. All Lines/Transformers with Thermal Violations in 2030

* Maximum of the loadings observed in the in the base case and the three sensitivities

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	Maximum Loadings*
26093	TARZANA	230	26087	OLYMPC	230	3	Line	259%
26093	TARZANA	230	26087	OLYMPC	230	1	Line	242%
26093	TARZANA	230	26087	OLYMPC	230	2	Line	242%
26073	WLMNTN	138	26091	HARBOR	138	D	Line	234%
26061	RINALDI	230	26094	SYLMARLA	230	4	Line	217%
26080	VELASCO	230	26081	ATWATER	230	1	Line	207%
26010	CASTAIC34	230	26086	NRTHRDGE	230	1	Line	178%
26065	SCATERGD	138	26089	AIRPORT	138	1	Line	169%
26065	SCATERGD	138	26089	AIRPORT	138	2	Line	169%
26061	RINALDI	230	26013	AIRWAY	230	1	Line	168%
26086	NRTHRDGE	230	26093	TARZANA	230	1	Line	166%
26063	RIVER	230	26080	VELASCO	230	1	Line	161%
26061	RINALDI	230	26013	AIRWAY	230	2	Line	157%

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	Maximum Loadings*
26068	STJOHN	230	26081	ATWATER	230	1	Line	156%
26136	COTTONWD	230	26132	BARRENRD	230	1	Line	153%
26083	HOLYWD1	138	26085	HOLYWDLD	138	1	Line	151%
26084	HOLYWD2	138	26085	HOLYWDLD	138	1	Line	151%
26268	TOL E	230	26082	HOLYWD_E	230	1	Line	146%
26013	AIRWAY	230	26081	ATWATER	230	1	Line	145%
26013	AIRWAY	230	26081	ATWATER	230	2	Line	145%
26076	FAIRFAX	138	26088	OLYMPCLD	138	A	Line	141%
26076	FAIRFAX	138	26088	OLYMPCLD	138	B	Line	141%
26076	FAIRFAX	138	26083	HOLYWD1	138	A	Line	125%
26076	FAIRFAX	138	26084	HOLYWD2	138	B	Line	125%
26061	RINALDI	230	26094	SYLMARLA	230	1	Line	123%
26061	RINALDI	230	26094	SYLMARLA	230	3	Line	120%
26268	TOL E	230	26081	ATWATER	230	1	Line	119%
26103	VALLEY	230	26078	TOLUCA	230	1	Line	116%
26103	VALLEY	230	26268	TOL E	230	2	Line	116%
26076	FAIRFAX	138	26014	GRAMERC1	138	1	Line	115%
26076	FAIRFAX	138	26014	GRAMERC1	138	2	Line	115%
26061	RINALDI	230	26103	VALLEY	230	2	Line	115%
26061	RINALDI	230	26103	VALLEY	230	1	Line	115%
26070	CNTURY1	287	26267	VIC13-16	287	1	Line	115%
26071	CNTURY2	287	26265	VIC18-15	287	1	Line	112%
26069	CNTURY	138	26073	WLMNTN	138	1	Line	112%
26069	CNTURY	138	26073	WLMNTN	138	2	Line	112%
26135	HSKLLCYN	230	26094	SYLMARLA	230	1	Line	111%
26094	SYLMARLA	230	26086	NRTHRDGE	230	1	Line	109%
26078	TOLUCA	230	26268	TOL E	230	1	Line	108%

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	Maximum Loadings*
26135	HSKLLCYN	230	26094	SYLMARLA	230	2	Line	107%
26091	HARBOR	138	26096	TAP 2	138	1	Line	104%
26068	STJOHN	230	26063	RIVER	230	1	Line	104%
26091	HARBOR	138	26095	TAP 1	138	1	Line	102%
26135	HSKLLCYN	230	26061	RINALDI	230	1	Line	101%
26094	SYLMARLA	230	24147	SYLMAR S	230	F	Tran	189%
26094	SYLMARLA	230	24147	SYLMAR S	230	E	Tran	189%
26088	OLYMPCLD	138	26087	OLYMPC	230	E	Tran	143%
26088	OLYMPCLD	138	26087	OLYMPC	230	F	Tran	143%
26262	SCA PS	138	26066	SCATERGD	230	E	Tran	116%
26065	SCATERGD	138	26262	SCA PS	138	E	Tran	116%
26085	HOLYWDLD	138	26182	HOLYWD_F	230	F	Tran	112%
26069	CNTURY	138	26072	CNTURYLD	230	E	Tran	108%
26069	CNTURY	138	26072	CNTURYLD	230	H	Tran	108%
26085	HOLYWDLD	138	26082	HOLYWD_E	230	E	Tran	108%
26070	CNTURY1	287	26069	CNTURY	138	F	Tran	106%

2045 Base Case

Table 57. 2045 Base Case Loadings Higher Than Those Listed in Table 56

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	Worst 2030 Loadings	Worst 2045 Base Case Loadings	% increase (wr.t Rating 2)
26061	RINALDI	230	26103	VALLEY	230	1	Line	115%	159%	44%
26061	RINALDI	230	26103	VALLEY	230	2	Line	115%	159%	44%
26076	FAIRFAX	138	26014	GRAMERC1	138	1	Line	115%	152%	37%
26076	FAIRFAX	138	26014	GRAMERC1	138	2	Line	115%	152%	37%
26076	FAIRFAX	138	26088	OLYMPCLD	138	A	Line	141%	151%	10%
26076	FAIRFAX	138	26088	OLYMPCLD	138	B	Line	141%	151%	10%
26070	CNTURY1	287	26267	VIC13-16	287	1	Line	115%	118%	3%
26071	CNTURY2	287	26265	VIC18-15	287	1	Line	112%	116%	4%
26103	VALLEY	230	26078	TOLUCA	230	1	Line	116%	118%	2%
26103	VALLEY	230	26268	TOL E	230	2	Line	116%	118%	2%
26069	CNTURY	138	26072	CNTURYLD	230	E	Tran	108%	126%	18%
26069	CNTURY	138	26072	CNTURYLD	230	H	Tran	108%	126%	18%
26070	CNTURY1	287	26069	CNTURY	138	F	Tran	106%	114%	8%
26085	HOLYWDLD	138	26082	HOLYWD_E	230	E	Tran	108%	110%	2%
26085	HOLYWDLD	138	26182	HOLYWD_F	230	F	Tran	112%	114%	2%

Table 58. New Line/Transformer Overloads Observed in 2045 Base Case Compared to the Violations Listed in Table 56

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	N-1	N-k	N-1-1	Maximum of N-1, N-k, and N-1-1 Loadings
26061	RINALDI	230	26093	TARZANA	230	1	Line	-	-	142%	142%
26061	RINALDI	230	26093	TARZANA	230	2	Line	-	0%	142%	142%
26051	MEAD	287	19012	MEAD S	230	M	Tran	119%	157%	157%	157%
26115	RINALDI2	500	26061	RINALDI	230	H	Tran	-	-	118%	118%
26061	RINALDI	230	26263	RING2DUM	500	G2	Tran	-	-	117%	117%
26062	RINALDI	500	26263	RING2DUM	500	G2	Tran	-	-	115%	115%
26062	RINALDI	500	26061	RINALDI	230	G1	Tran	-	-	113%	113%
26102	VALLEY	138	26103	VALLEY	230	E	Tran	-	-	111%	111%
26102	VALLEY	138	26103	VALLEY	230	F	Tran	-	-	111%	111%
26102	VALLEY	138	26103	VALLEY	230	G	Tran	-	-	111%	111%

2045 Monsoon Sensitivity Case

Table 59. Lines/Transformers in the 2045 Monsoon Sensitivity Case with Loadings Greater than Those Listed in Table 56, Table 57, and Table 58

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	Highest Loadings in 2030 and 2045 Base Case	Highest 2045 Monsoon Sensitivity Loadings	% increase (wr.t Rating 2)
26076	FAIRFAX	138	26014	GRAMERC1	138	1	Line	152%	154%	2%
26076	FAIRFAX	138	26014	GRAMERC1	138	2	Line	152%	154%	2%
26091	HARBOR	138	26096	TAP 2	138	1	Line	104%	106%	2%
26091	HARBOR	138	26095	TAP 1	138	1	Line	102%	104%	2%

Table 60. New Overloads Observed in 2045 Monsoon Sensitivity Compared to the Violations Listed in Table 56, Table 57, and Table 58

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	N-1	N-k
26073	WLMNTN	138	26091	HARBOR	138	E	Line	110%	105%

2045 Northern Imports Sensitivity Case

Table 61. Lines/Transformers in the 2045 Northern Imports Sensitivity Case with Loadings Greater than Those Listed in Table 56, Table 57, and Table 58

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	Highest Loadings in 2030 and 2045 Base Case	Highest 2045 Northern Imports Sensitivity Loadings	% increase (wr.t Rating 2)
26268	TOL E	230	26081	ATWATER	230	1	Line	119%	181%	62%
26061	RINALDI	230	26013	AIRWAY	230	1	Line	168%	193%	25%
26061	RINALDI	230	26013	AIRWAY	230	2	Line	157%	180%	23%
26078	TOLUCA	230	26268	TOL E	230	1	Line	108%	128%	20%
26010	CASTAIC34	230	26086	NRTHRDGE	230	1	Line	178%	185%	7%
26061	RINALDI	230	26094	SYLMARLA	230	4	Line	217%	222%	5%
26086	NRTHRDGE	230	26093	TARZANA	230	1	Line	166%	169%	3%
26061	RINALDI	230	26094	SYLMARLA	230	1	Line	123%	126%	3%
26135	HSKLLCYN	230	26061	RINALDI	230	1	Line	101%	104%	3%
26061	RINALDI	230	26094	SYLMARLA	230	3	Line	120%	122%	2%
26135	HSKLLCYN	230	26094	SYLMARLA	230	2	Line	107%	109%	2%
26135	HSKLLCYN	230	26094	SYLMARLA	230	1	Line	111%	112%	1%
26094	SYLMARLA	230	24147	SYLMAR S	230	F	Tran	189%	196%	7%
26094	SYLMARLA	230	24147	SYLMAR S	230	E	Tran	189%	196%	7%

Table 62. New Overloads Observed in 2045 Northern Imports Sensitivity Compared to the Violations Listed in Table 56, Table 57, and Table 58

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	N-1	N-k
26286	HAY N	230	26081	ATWATER	230	1	Line	-	104%
26094	SYLMARLA	230	24147	SYLMAR S	230	G	Tran	-	100%

2045 VIC-LA Sensitivity Case

Table 63. Lines/Transformers in the 2045 VIC-LA Sensitivity Case with Loadings Greater than Those Listed in Table 56, Table 57, and Table 58

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	Highest Loadings in 2030 and 2045 Base Case	Highest 2045 VIC-LA Sensitivity Loadings	% increase (wr.t Rating 2)
26051	MEAD	287	19012	MEAD S	230	M	Tran	157%	157%	0.01%

Table 64. New Overloads Observed in 2045 VIC-LA Sensitivity Compared to the Violations Listed in Table 56, Table 57, and Table 58

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	N-1	N-k
26079	TOLUCA	500	26078	TOLUCA	230	G	Tran	-	103%

Table 65. Lines/Transformers that Need Upgrading Again in 2045

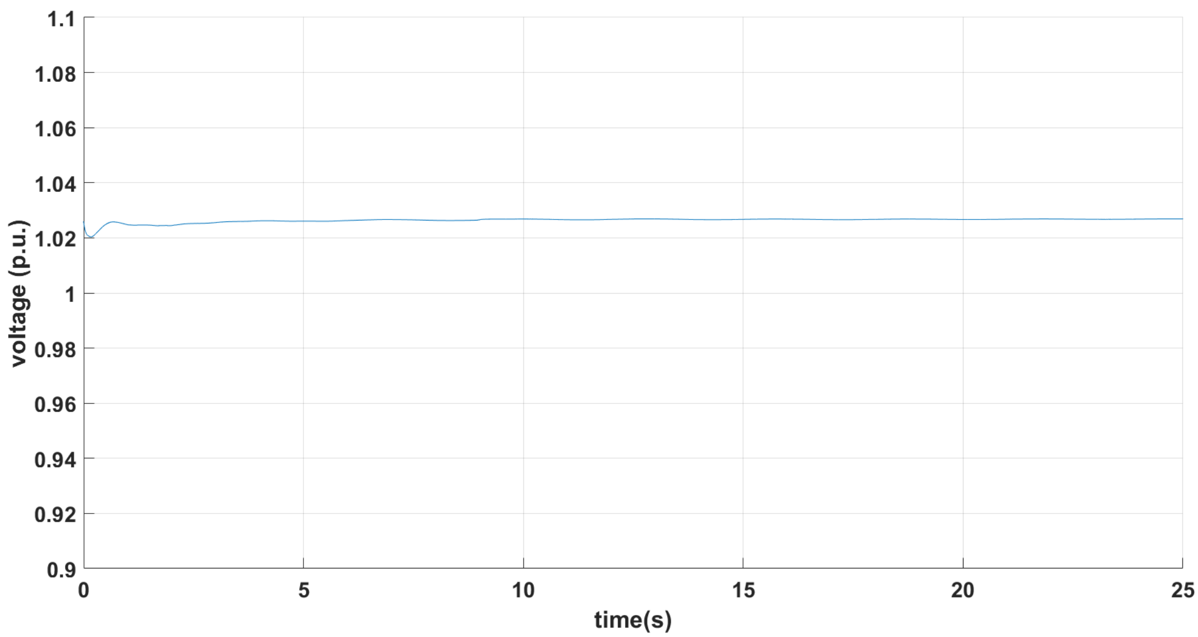
From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	Worst 2030 Loadings	Worst 2045 Loadings	% increase (w.r.t Rating 2)
26268	TOL E	230	26081	ATWATER	230	1	Line	119%	181%	62%
26061	RINALDI	230	26103	VALLEY	230	1	Line	115%	159%	44%
26061	RINALDI	230	26103	VALLEY	230	2	Line	115%	159%	44%
26076	FAIRFAX	138	26014	GRAMERC1	138	1	Line	115%	154%	39%
26076	FAIRFAX	138	26014	GRAMERC1	138	2	Line	115%	154%	39%
26061	RINALDI	230	26013	AIRWAY	230	1	Line	168%	193%	25%
26061	RINALDI	230	26013	AIRWAY	230	2	Line	157%	180%	23%
26078	TOLUCA	230	26268	TOL E	230	1	Line	108%	128%	20%
26076	FAIRFAX	138	26088	OLYMPCLD	138	A	Line	141%	151%	10%
26076	FAIRFAX	138	26088	OLYMPCLD	138	B	Line	141%	151%	10%
26010	CASTAIC34	230	26086	NRTHRDGE	230	1	Line	178%	185%	7%
26061	RINALDI	230	26094	SYLMARLA	230	4	Line	217%	222%	5%
26071	CNTURY2	287	26265	VIC18-15	287	1	Line	112%	116%	4%

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	Worst 2030 Loadings	Worst 2045 Loadings	% increase (w.r.t Rating 2)
26086	NRTHRDGE	230	26093	TARZANA	230	1	Line	166%	169%	3%
26061	RINALDI	230	26094	SYLMARLA	230	1	Line	123%	126%	3%
26070	CNTURY1	287	26267	VIC13-16	287	1	Line	115%	118%	3%
26135	HSKLLCYN	230	26061	RINALDI	230	1	Line	101%	104%	3%
26061	RINALDI	230	26094	SYLMARLA	230	3	Line	120%	122%	2%
26103	VALLEY	230	26078	TOLUCA	230	1	Line	116%	118%	2%
26103	VALLEY	230	26268	TOL E	230	2	Line	116%	118%	2%
26135	HSKLLCYN	230	26094	SYLMARLA	230	2	Line	107%	109%	2%
26091	HARBOR	138	26096	TAP 2	138	1	Line	104%	106%	2%
26091	HARBOR	138	26095	TAP 1	138	1	Line	102%	104%	2%
26135	HSKLLCYN	230	26094	SYLMARLA	230	1	Line	111%	112%	1%
26069	CNTURY	138	26072	CNTURYLD	230	E	Tran	108%	126%	17%
26069	CNTURY	138	26072	CNTURYLD	230	H	Tran	108%	126%	16%
26070	CNTURY1	287	26069	CNTURY	138	F	Tran	106%	114%	8%
26094	SYLMARLA	230	24147	SYLMAR S	230	E	Tran	189%	196%	4%
26094	SYLMARLA	230	24147	SYLMAR S	230	F	Tran	189%	196%	4%
26085	HOLYWDLD	138	26182	HOLYWD_F	230	F	Tran	112%	114%	2%
26085	HOLYWDLD	138	26082	HOLYWD_E	230	E	Tran	108%	110%	2%

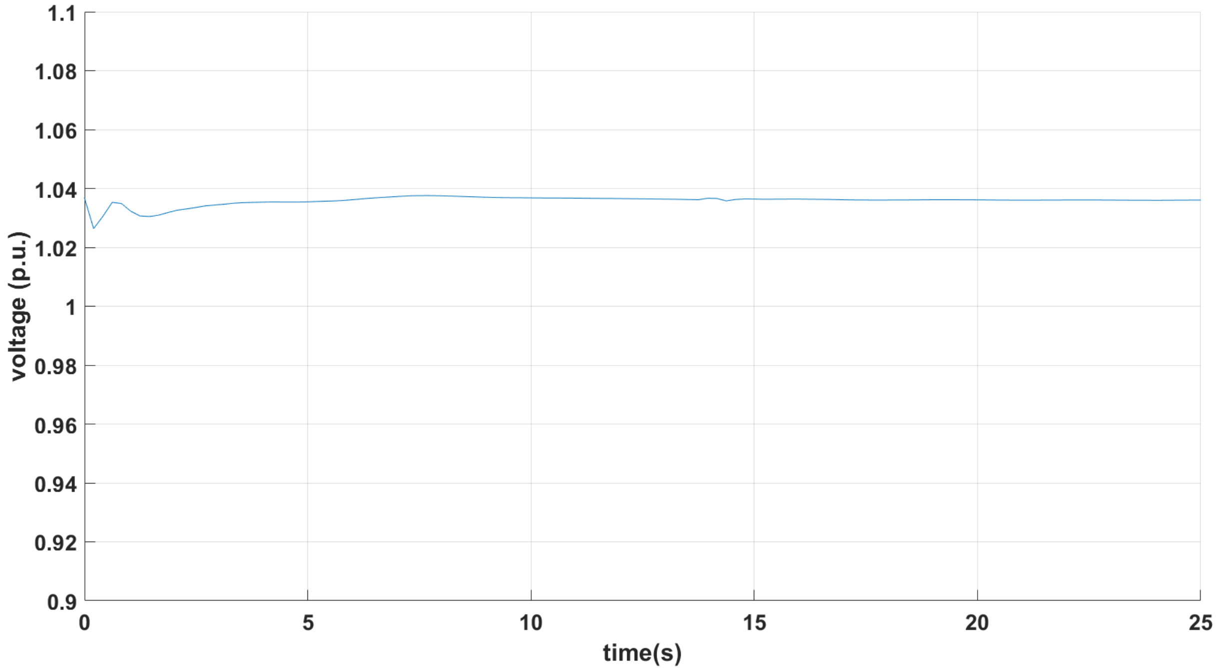
E.4 Transient Contingency Analysis

No-Disturbance Dynamic Simulation

Transient contingency analysis was only performed for the 2030 and 2045 base cases. Before starting the contingency analysis, we ensured that a stable operating point existed, which was disturbed by each contingency to evaluate the dynamic performance of the post-contingency LADWP power system. The average bus voltage and frequency in LADWP, calculated over all buses with nominal voltages equal to or exceeding 100 kV, are shown in Figure 76 and Figure 77, respectively. These profiles suggest a stable pre-disturbance operating point for both 2030 and 2045 although both years show a small initial transient before a steady state is established. The initial transient is also slightly larger in 2045 compared to 2030.

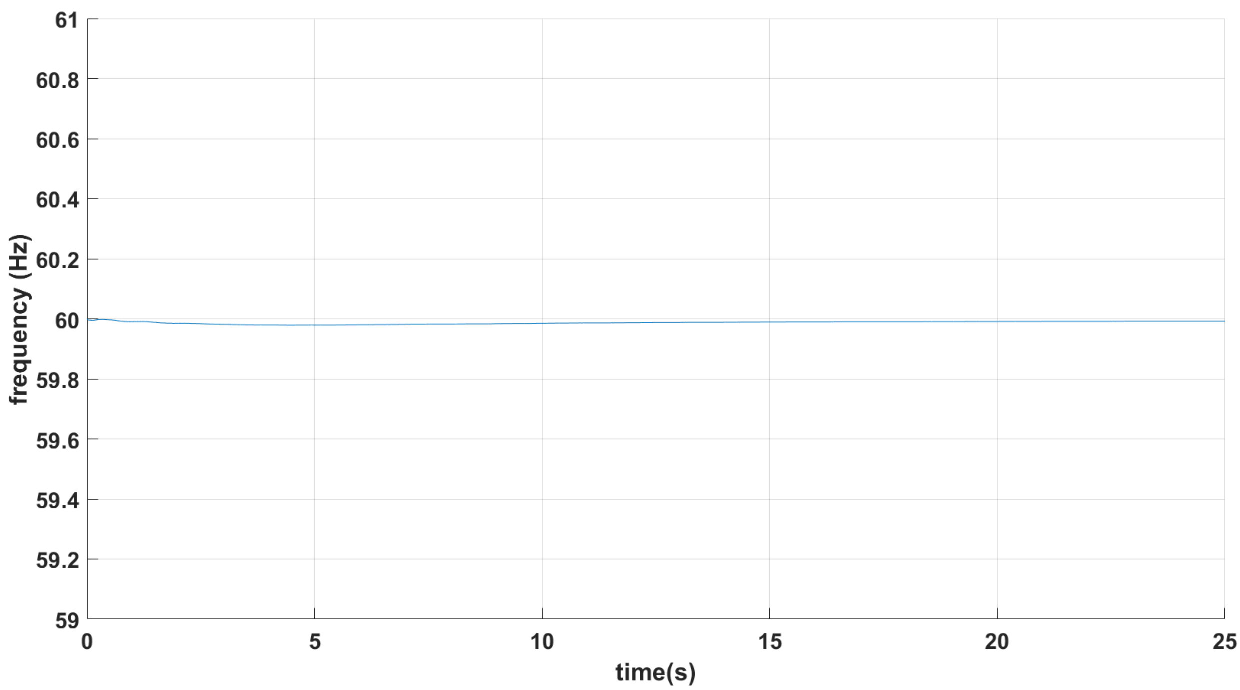


(a) 2030

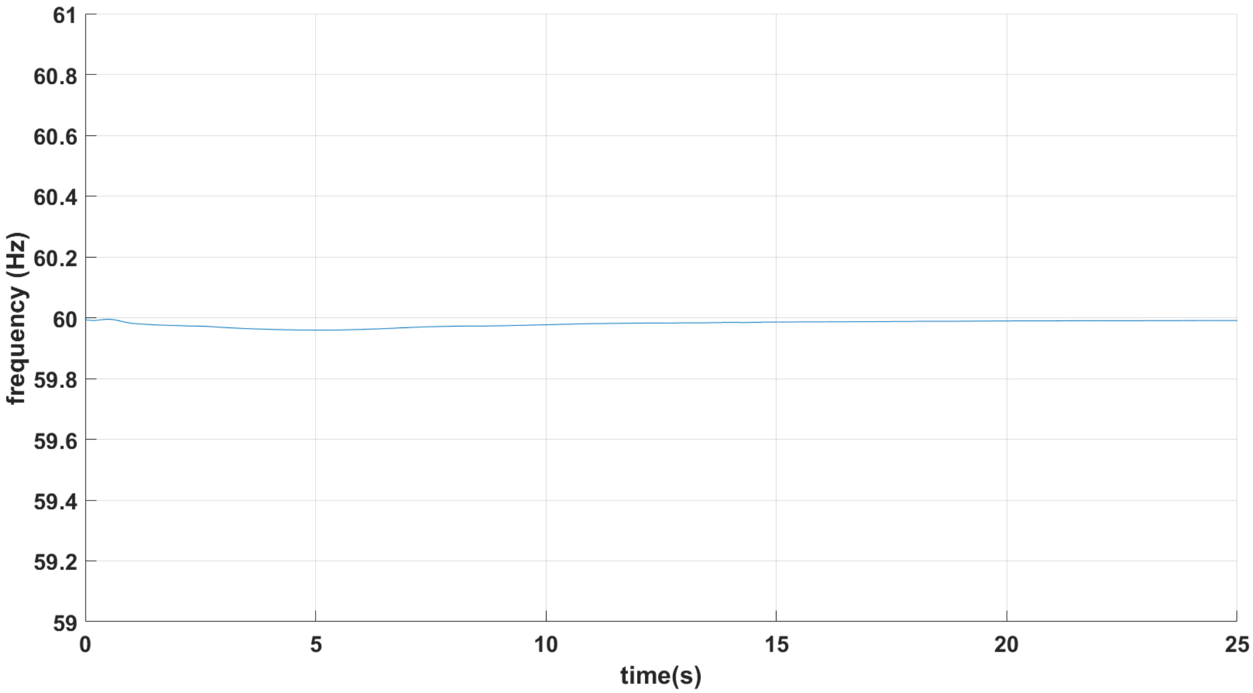


(b) 2045

Figure 76. No-disturbance average bus voltage in LADWP in (a) 2030 (b) 2045



(a) 2030



(b) 2045

Figure 77. No-disturbance average bus frequency in LADWP in (a) 2030 (b) 2045

Transient Contingency Analysis for 2030 and 2045 Base Cases

A total 238 and 248 transient contingencies were run for the 2030 and 2045 base cases, respectively. Almost all transient contingencies involved application of severe faults that were cleared after some time (ranging from 4, 60 Hz cycles or 0.0667 seconds to 26, 60 Hz cycles or 0.4333 seconds). When the fault was cleared, one or more lines, transformers, and other bulk power system elements were also taken out of service. The contingencies belonged to several categories with the severity of impact expected to increase from P1 to Extreme categories. Contingencies associated with the unexpected outage of one or both poles of the PDCI and IPPDC DC lines were also simulated. The number of contingencies by categories that were run in 2030 and 2045 are listed in Table 66.

While most of the contingencies were provided to us by LADWP, we added some more in the P1 category to simulate three-phase-to-ground fault at all the generator buses that we added in 2030 and 2045 base cases. This is the reason for the difference in the number of transient contingencies that were run in 2030 and 2045.

Table 66. Transient Contingencies by Category Simulated for 2030 and 2045 Base Cases

	2030			2045		
Contingency Category	**Contingency Count**	**Violations**	**Divergence**	**Contingency Count**	**Violations**	**Divergence**
P1	78	-	-	88	-	-
P2	12	-	-	12	-	-
P3	9	-	-	9	-	-
P4	59	-	1	59	-	-
P5	32	1	1	32	1	-
P6	8	-	-	8	-	-
P7	22	-	1	22	-	-
Extreme	14	1	2	14	-	1
PDCI Monopole	1	-	-	1	-	-
PDCI Bipole	1	-	-	1	-	-
IPPDC Monopole	1	-	-	1	-	-
IPPDC Bipole	1	-	-	1	-	-
Total	**238**	**2**	**5**	**248**	**1**	**1**

Transient Performance Criteria Violations in 2030 Transient Contingency Analysis

As discussed in Appendix D, we followed the transient voltage performance criteria given in TPL-001-WECC-CRT-3.1 to identify contingencies that did not result in acceptable performance. In addition, we also identified contingencies that diverged, and which would not be flagged by PSLF as being violative of TPL-001-WECC-CRT-3.1. We also observed the average voltage profiles to identify any additional contingencies that satisfied TPL-001-WECC-CRT-3.1 but did not result in a steady post-transient operating point.[75]

Transient Contingencies that Showed TPL-001-WECC-CRT-3.1 Criteria Violations

Of the 238 contingencies that we ran, only two contingencies showed violations according to the TPL-001-WECC-CRT-3.1 Criteria. These contingencies are P5_TOL or the Loss of Toluca (RS-E) 230kV Station following a single-line-ground fault, and the Extreme contingency Line_01, which also involves loss of the 230 kV Toluca substation, but the severity of the fault is higher

[75] All generators in LADWP were equipped with low/high voltage/frequency ride-through relays whose settings were either kept the same as in the file provided to us by LADWP or were set to parameters as per the PRC-024-2 standard as applicable to WECC. While generators could trip on account of low/high voltages, only an alarm was setoff under low/high frequency conditions. This was done because of inaccuracies in frequency calculations under certain conditions in positive sequence power flow/dynamics software, which includes PSLF. This issue was flagged in a recent WECC whitepaper: P. Pourbeik, J. Weber, R. Majumdar, Sam (Shengqiang) Li, Juan J. Sanchez-Gasca, M. Torgesen, and D. Davies, *WECC White Paper on Understanding Frequency Calculation in Positive Sequence Stability Programs* (Western Electricity Coordinating Council, 2018), https://www.wecc.org/Reliability/WECC_White_Paper_Frequency_062618_Clean_Final.pdf.

because it is a three-phase-ground fault. The average voltage profiles for these contingencies are shown in Figure 78 and Figure 79, respectively.

For the P5_TOL single-line-to-ground contingency, 50 buses in LADWP showed TPL-001-WECC-CRT-3.1 Criteria violations (all three criterion were violated). Voltages are low at some of the buses in LADWP (e.g., Hollywood and Toluca) but other voltages are okay resulting in higher average voltages seen in Figure 78. For Line_01 contingency, 35 load buses showed the criteria violations. Similar to P5_TOL, all three criterion were violated.

For the Line_01 three-phase-to-ground fault contingency, although the average voltage in LADWP is not very low, it shows an oscillatory behavior between 5 and 10 seconds. The criterion that voltage should not fall below 70% of its initial value for more than 0.5 seconds once it recovers over 80% after a fault is the one that is violated at most of the buses with voltage violations.

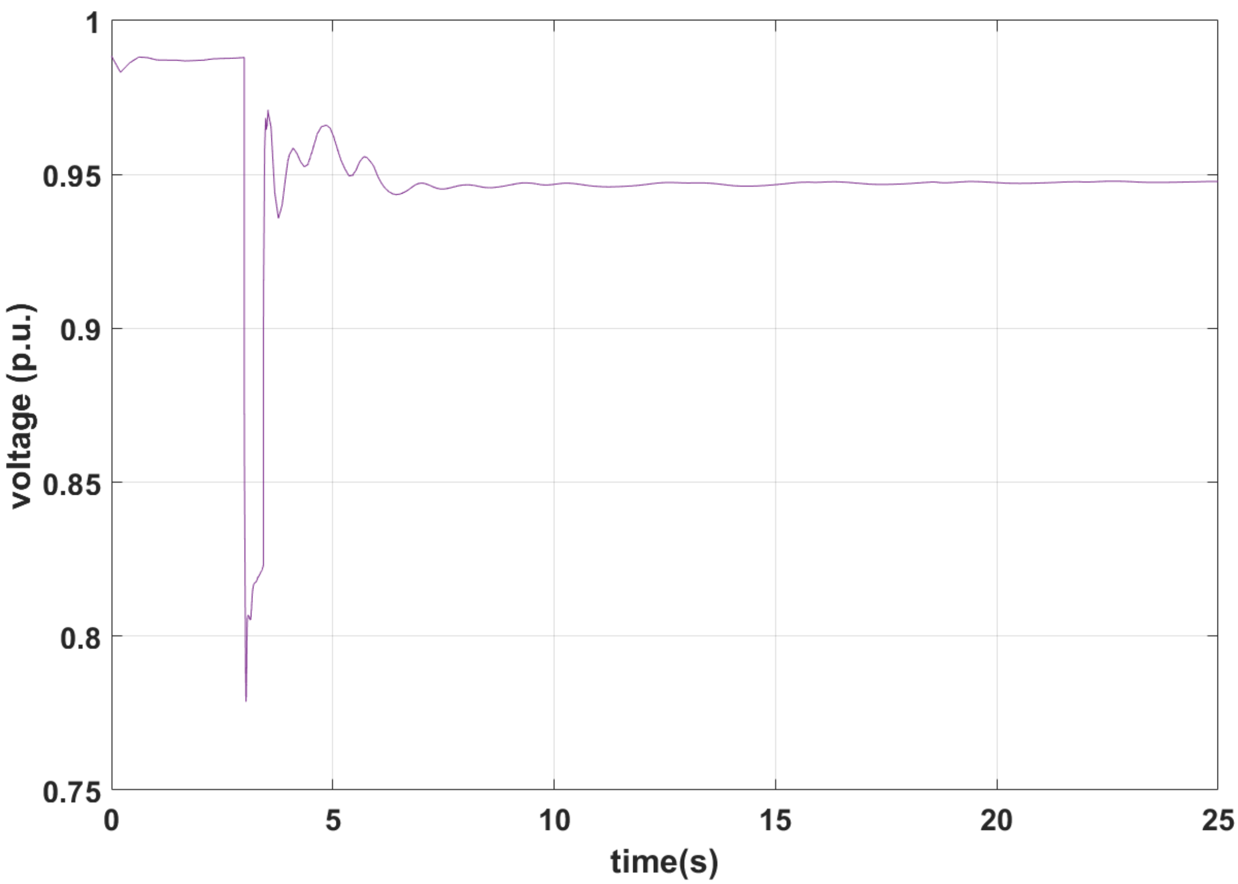


Figure 78. Average bus voltages in LADWP for the category P5, P5_TOL contingency

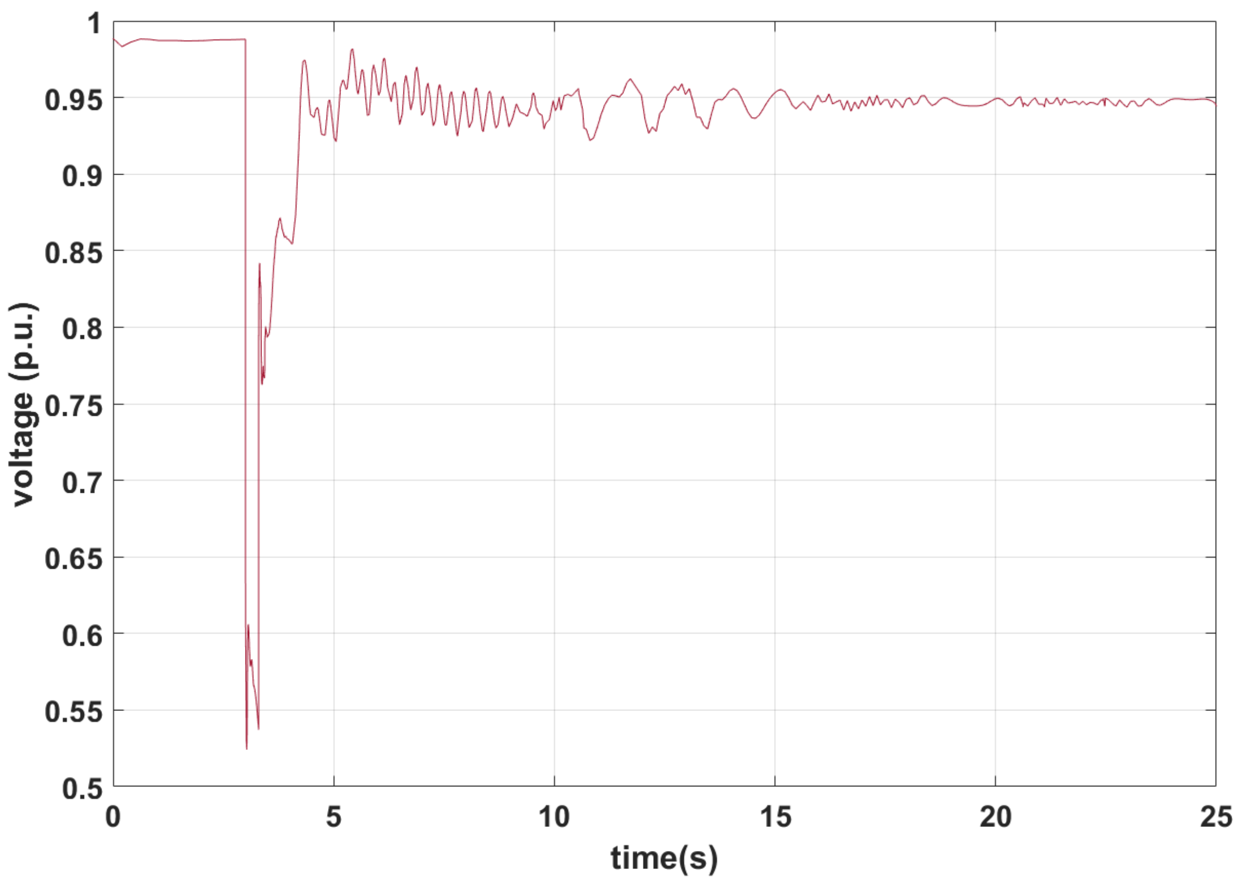


Figure 79. Average bus voltages in LADWP for the extreme category, Line_01 contingency

Transient Contingencies that Diverged

Five transient contingencies diverged. These are listed in Table 67 along with the probable causes of divergence and potential mitigation measures that would prevent divergence. Before running the transient simulations again for these contingencies, we created a new base case where the connection between LADWP and SCE through the INYO phase shifter was severed. This change was probably needed only for the P5_HSK contingency, but for simplicity we used this changed base case for all the five simulations. Moreover, we disabled tripping based on low/high frequency relay set points for the all the new generators that we added in LADWP. This was done both to help find a solution for these contingencies and because of NERC guidance that the region outside PRC-024-2 "no trip" zone is "may trip" and not "must trip."[76]

[76] NERC, *Reliability Guideline BPS-Connected Inverter-Based Resource Performance* (North American Electric Reliability Corporation, 2018). https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf.

Table 67. Transient Contingencies that Diverged in 2030 Base Case

Contingency Category	Contingency Number	Contingency Description	Probable Cause for Divergence	Potential Solution
P4	P4_58	Three-phase-ground fault at the 230 kV Barren Ridge Substation, which is cleared in 12 cycles. Inyo-Barren Ridge 230 kV line and one of the three Barren Ridge-Rosamond lines are opened when the fault is cleared.	4 cycle delay in RAS action to trip generation in the region that results in more power injection than the weakened network can handle. This is because a lot of renewable generation is added in the North.	If RAS action that removes generation at Cottonwood simultaneously with the fault being cleared, then the simulations do not diverge.
P5	P5_HSK	Three-phase-ground fault at the 230 kV Haskell Canyon Substation, followed by the entire substation being out of service as the fault is cleared	Same as above	If RAS action that removes all generation upstream of Haskell Canyon takes place simultaneously with the fault being cleared, then the simulations do not diverge.
P7	P7_BAR_ ROSA_2&3	Three-phase-ground fault at the 230 kV Barren Ridge substation, followed by two of the three Barren Ridge-Rosamond lines being opened when the fault is cleared.	Same as above	If RAS action that removes generation around Barren Ridge takes place simultaneously with the fault being cleared, then the simulations do not diverge.
Extreme	Line_03	Three-phase-ground fault at the 230 kV Barren Ridge substation, followed all three Barren Ridge-Rosamond lines being opened when the fault is cleared.	Same as above	
Extreme	Line_14	Three-phase fault at the 500 kV Adelanto bus followed by loss of five lines - Adelanto-Toluca 500 kV line, two, 230 kV lines between Valley and Toluca, and two, 230 kV lines between Airway and Rinaldi	Significantly higher flow over the lines that go out of service than in the 2028 case. The resulting re-direction of power results in instability	If LADWP generators are able to ride-through the fault duration and do not trip on account of voltage drops, the contingency does not diverge. However, the post-disturbance steady-state voltages are low and oscillatory.

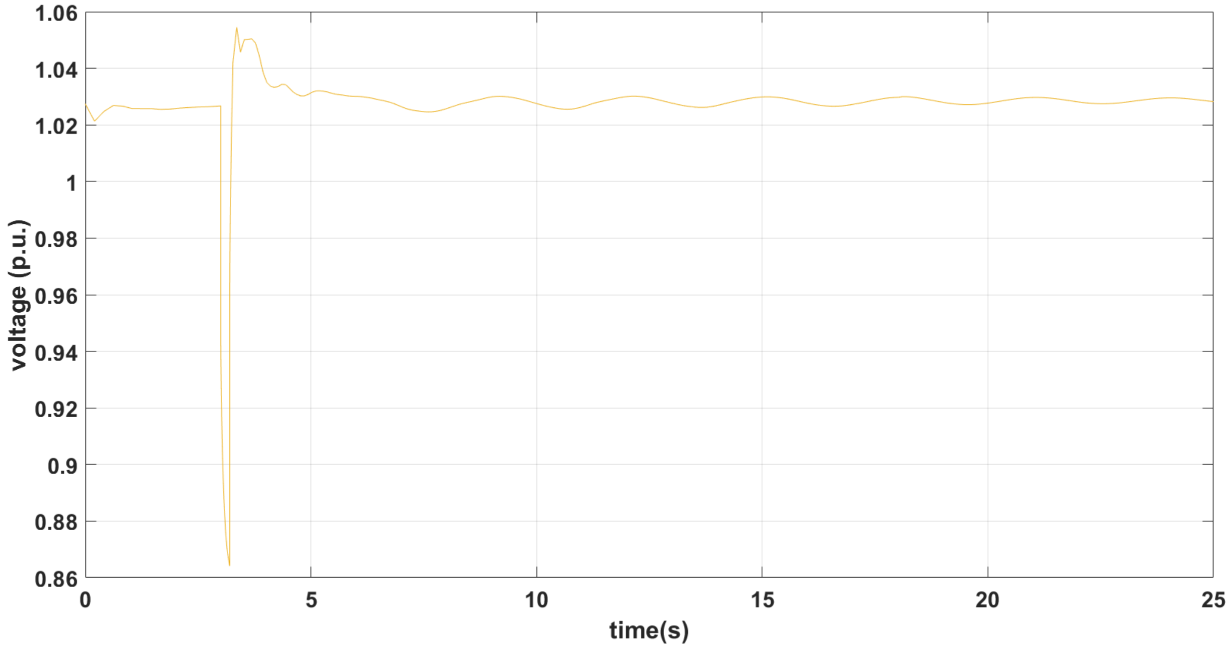


Figure 80. Average bus voltages in Area 26 (LADWP) for P4_58 contingency

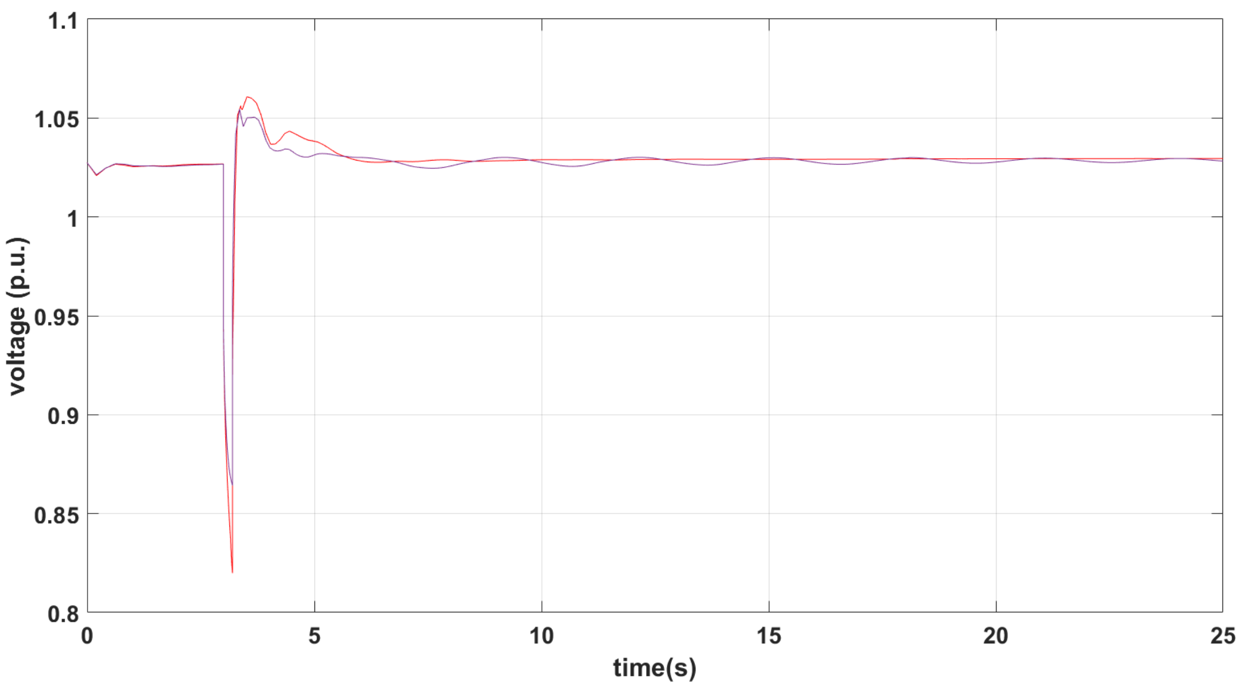


Figure 81. Average bus voltages in Area 26 (LADWP) for P5_HSK contingency

Blue curve without reec_c model parameter fix. Red curve with the reec_c model parameter fix.

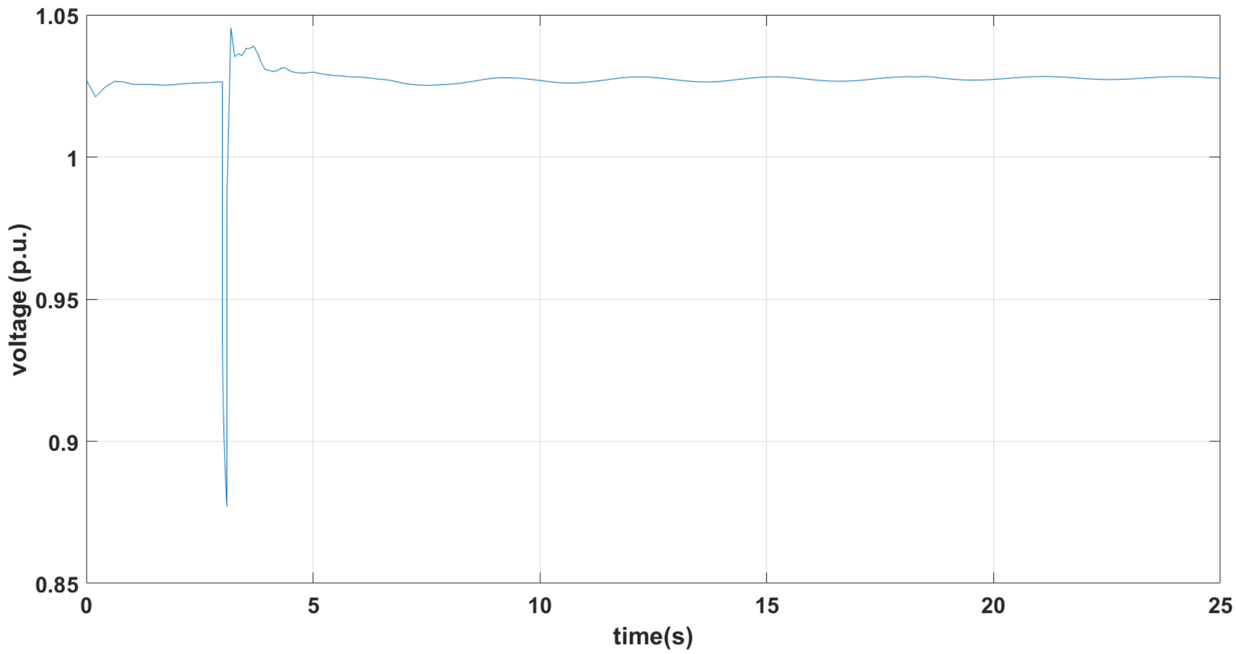


Figure 82. Average bus voltages in Area 26 (LADWP) for P7_BAR_ROSA_2&3 contingency

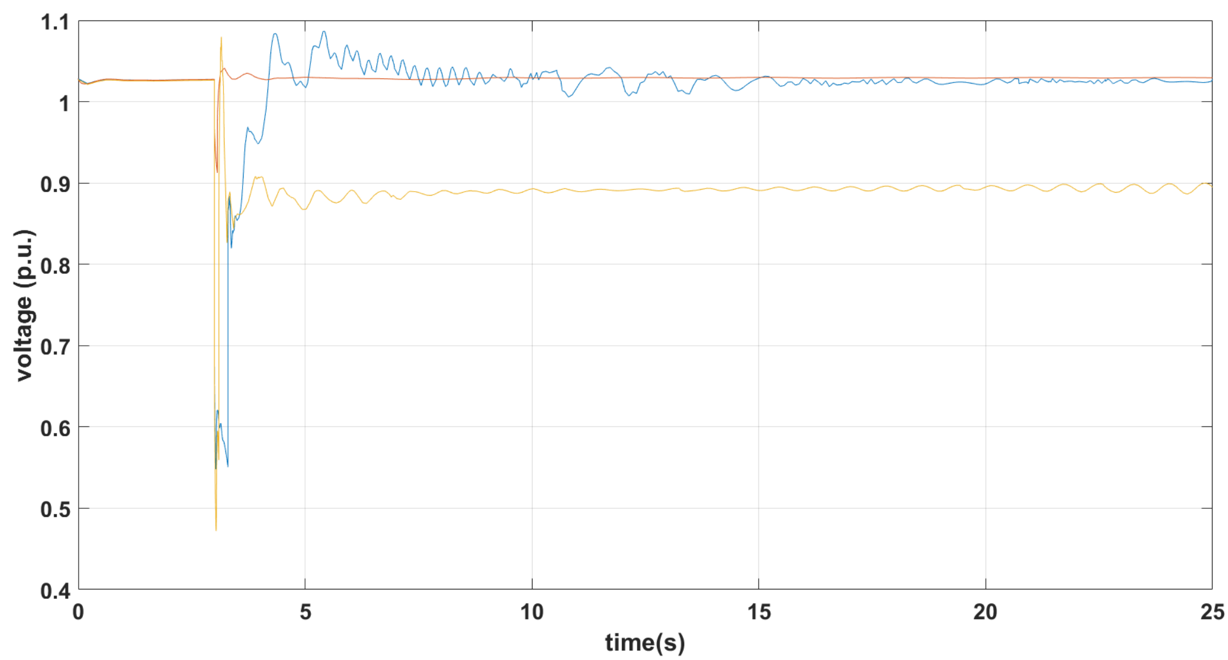


Figure 83. Average bus voltages in Area 26 (LADWP) for Line_01 (blue curve), Line_03 (red curve), and Line_14 (green curve) extreme contingencies

From Figure 80, Figure 82 and Figure 83, it can be observed that the post-disturbance average voltages are oscillatory. On a closer examination of the results, it was found that four renewable generators connected at the 230 kV North Ridge, Tarzana, Rinaldi, and Toluca buses were oscillating against the renewable generator connected at the 500 kV Adelanto bus. This was because of the choice of reec_c and repc_a flags for these generators that was resulting in voltage control from the repc_a model and reactive power control from the reec_c model. By making the repc_a model control the terminal voltage and making the reec_c model follow the reactive power command provided by the repc_a model, these generators stopped oscillating against each other, which flatted the voltages. This is shown in Figure 81 for the P5_HSK contingency and the same fix will work for the P4_58 and P7_BAR_ROSA_2&3 contingencies.

Transient Contingencies in 2030 with Unsatisfactory Performance

Except for the contingencies listed above, we did not find any other contingency that had unsatisfactory performance. The average voltage plots for various contingency categories are shown next, in Figure 84 through Figure 106.

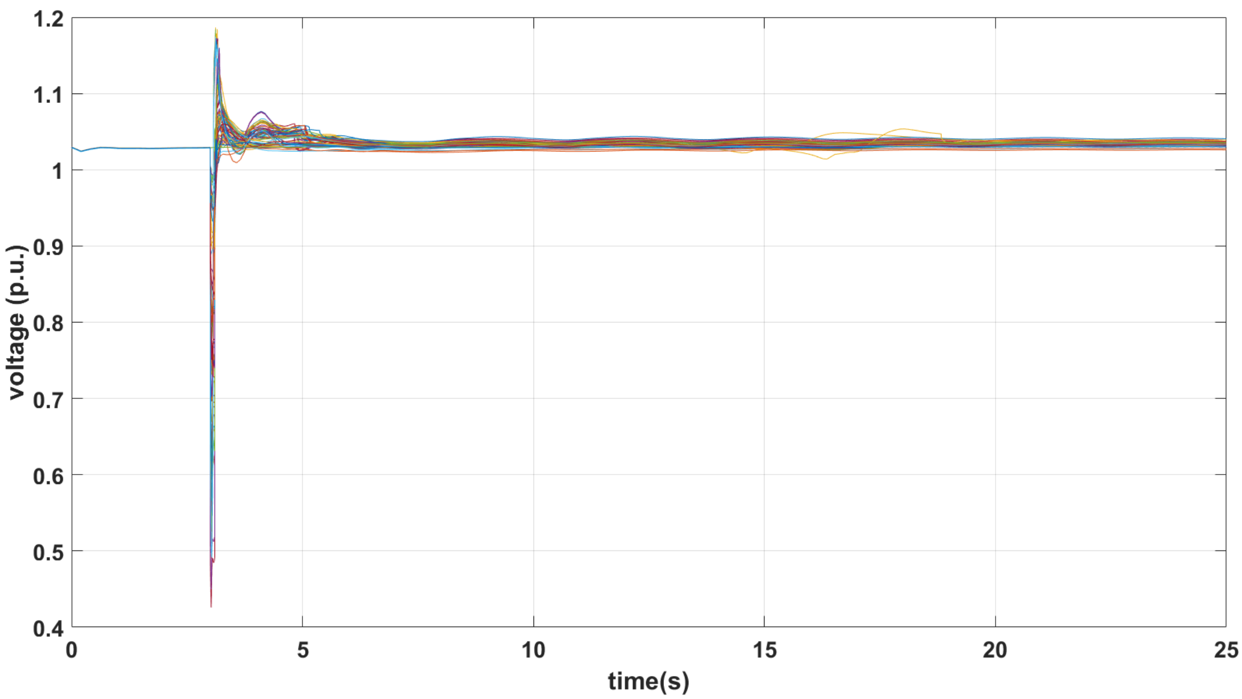


Figure 84. Average bus voltages in Area 26 (LADWP) for all P1 category contingencies

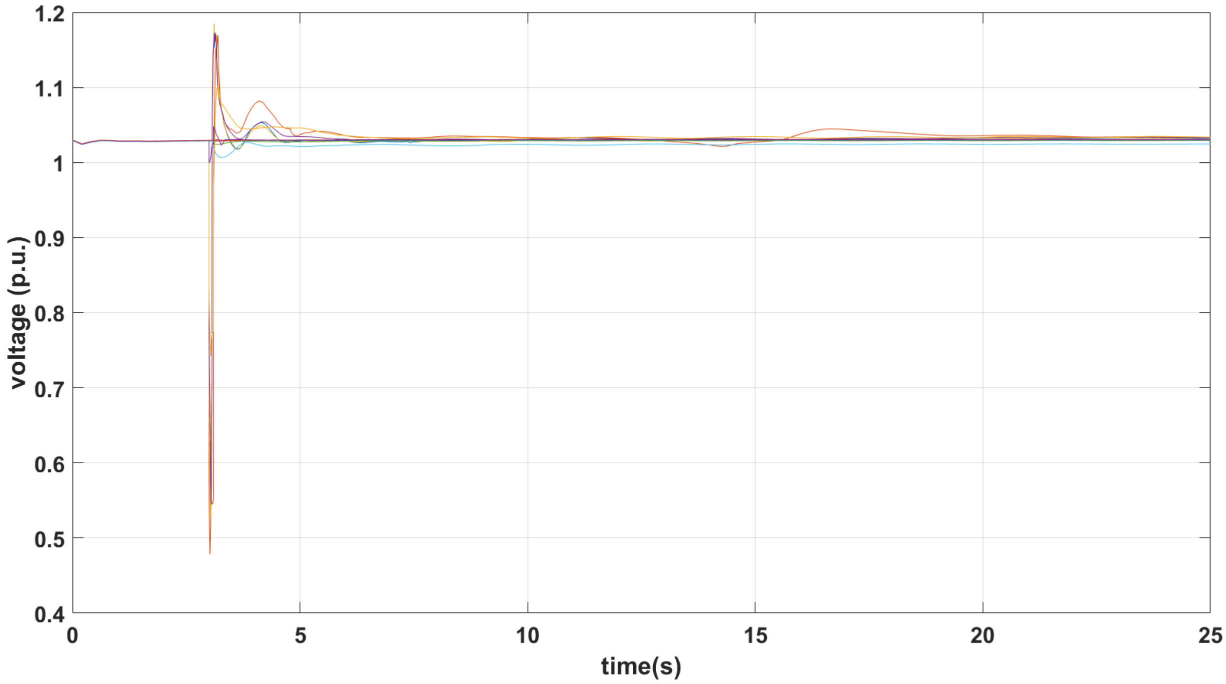


Figure 85. Average bus voltages in Area 26 (LADWP) for all P2 category contingencies

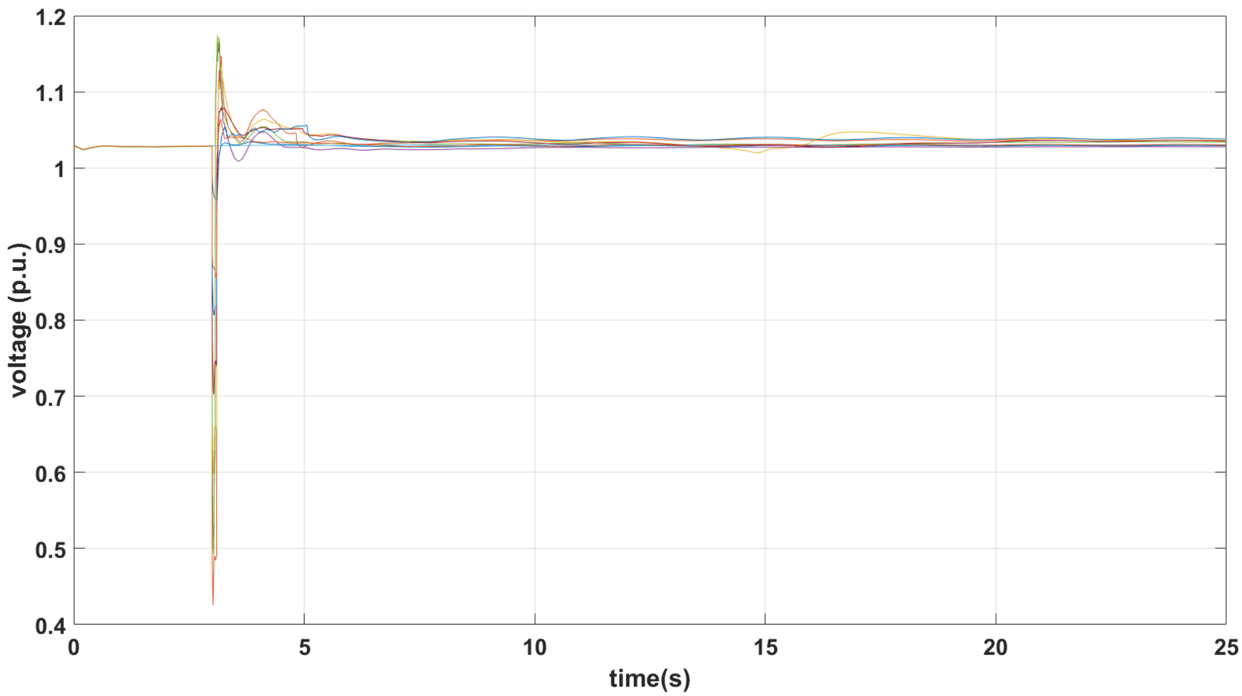


Figure 86. Average bus voltages in Area 26 (LADWP) for all P3 category contingencies

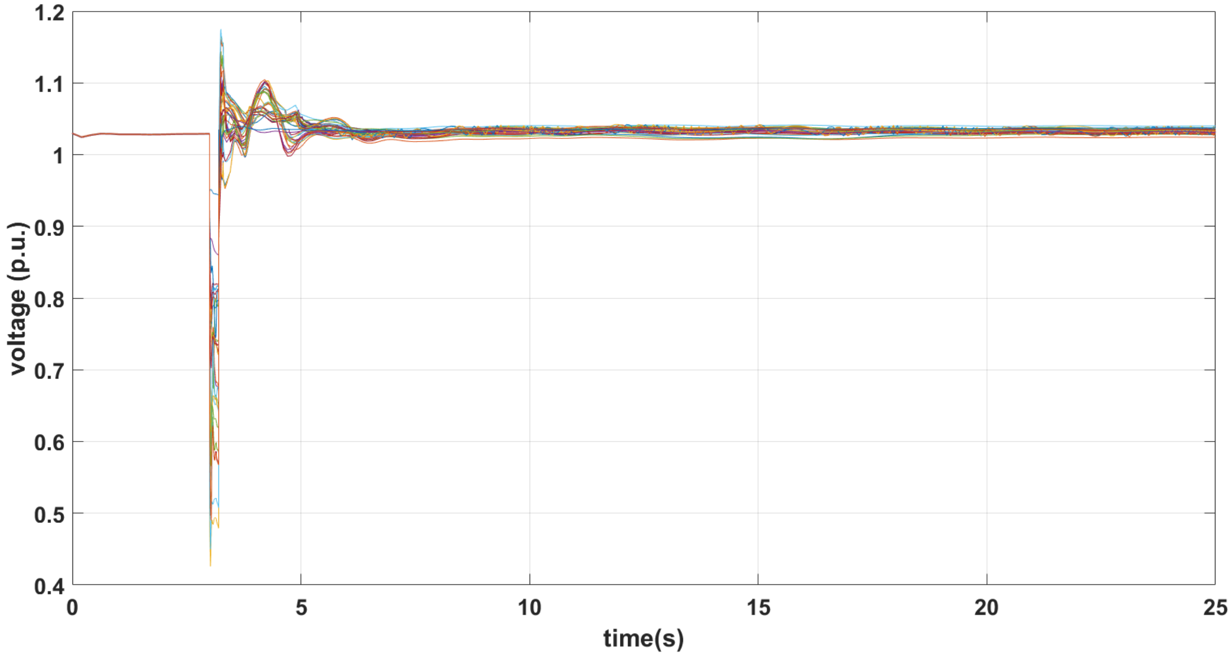


Figure 87. Average bus voltages in Area 26 (LADWP) for all but one P4 category contingencies

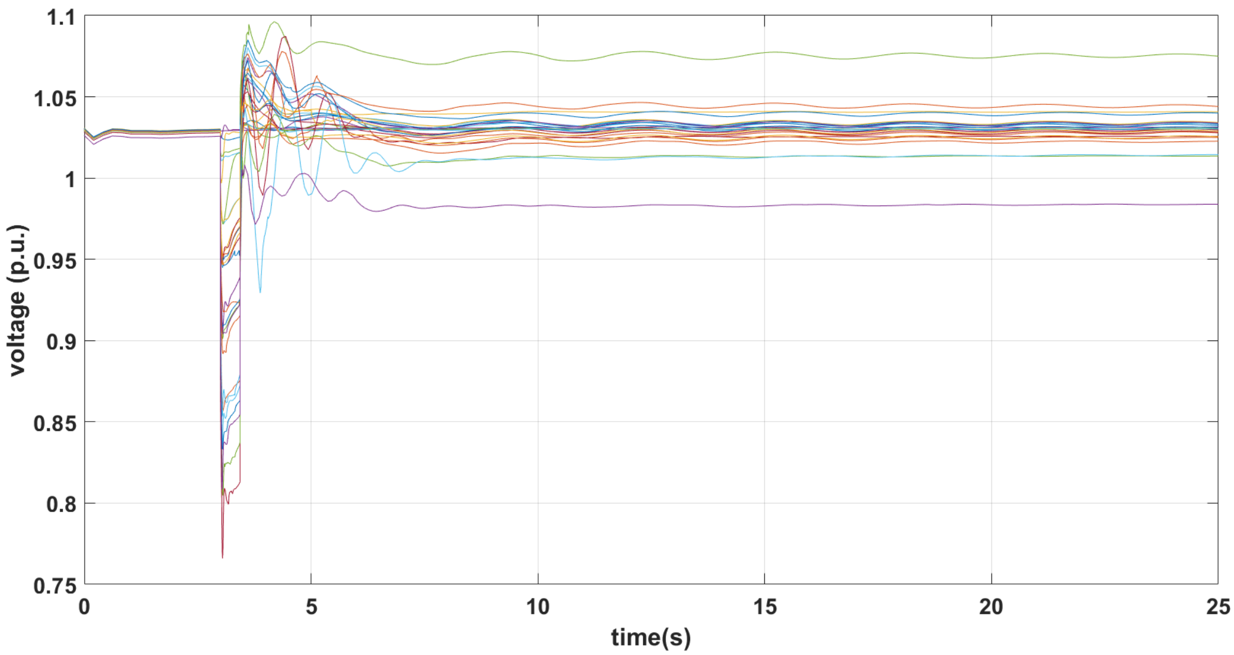


Figure 88. Average bus voltages in Area 26 (LADWP) for all but one P5 category contingencies

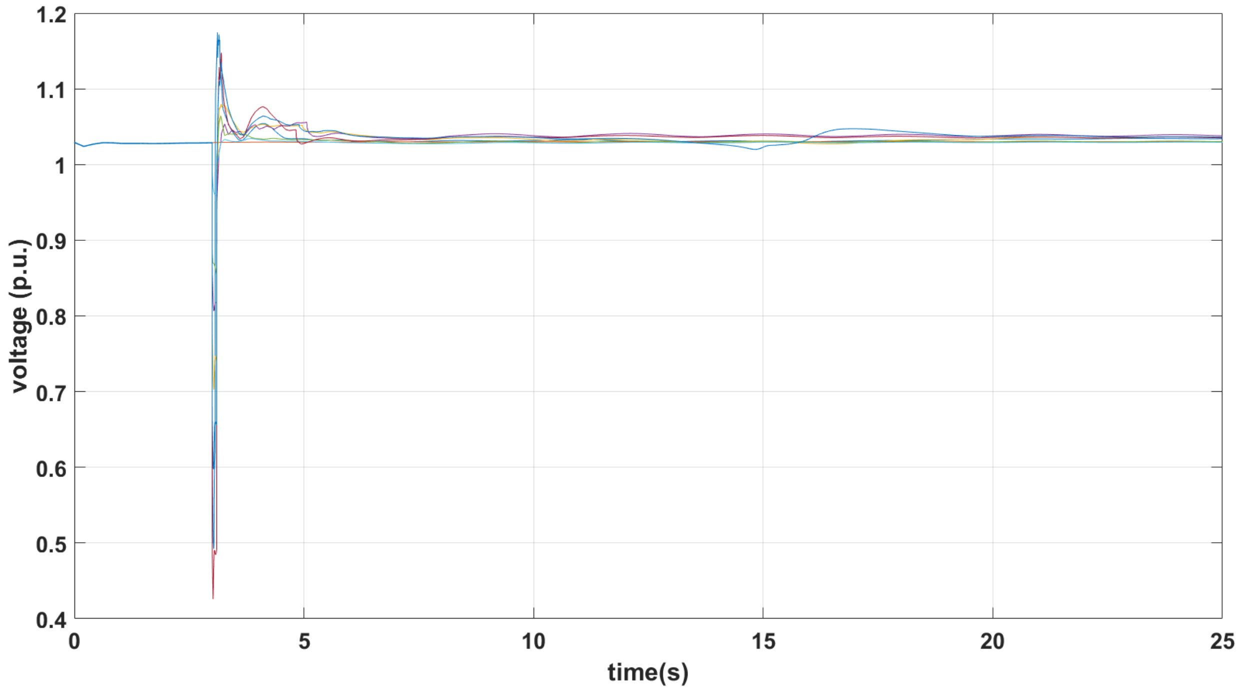


Figure 89. Average bus voltages in Area 26 (LADWP) for all P6 category contingencies

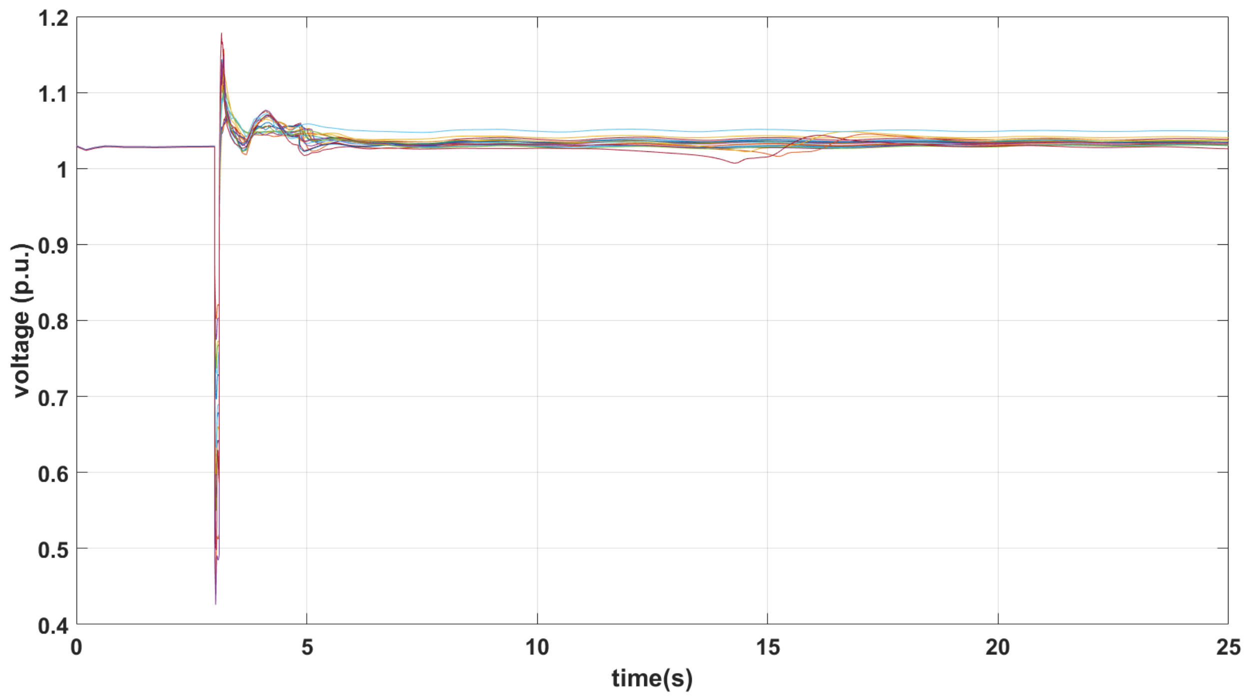


Figure 90. Average bus voltages in Area 26 (LADWP) for all but one P7 category contingencies

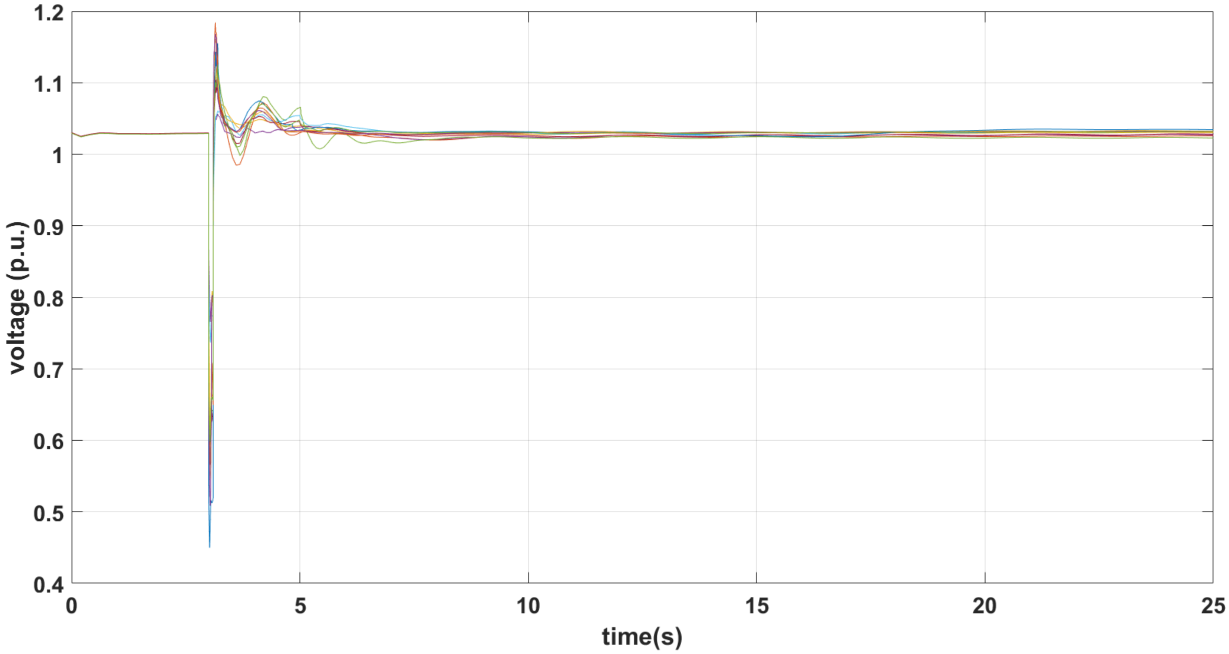


Figure 91. Average bus voltages in Area 26 (LADWP) for all but two extreme category contingencies

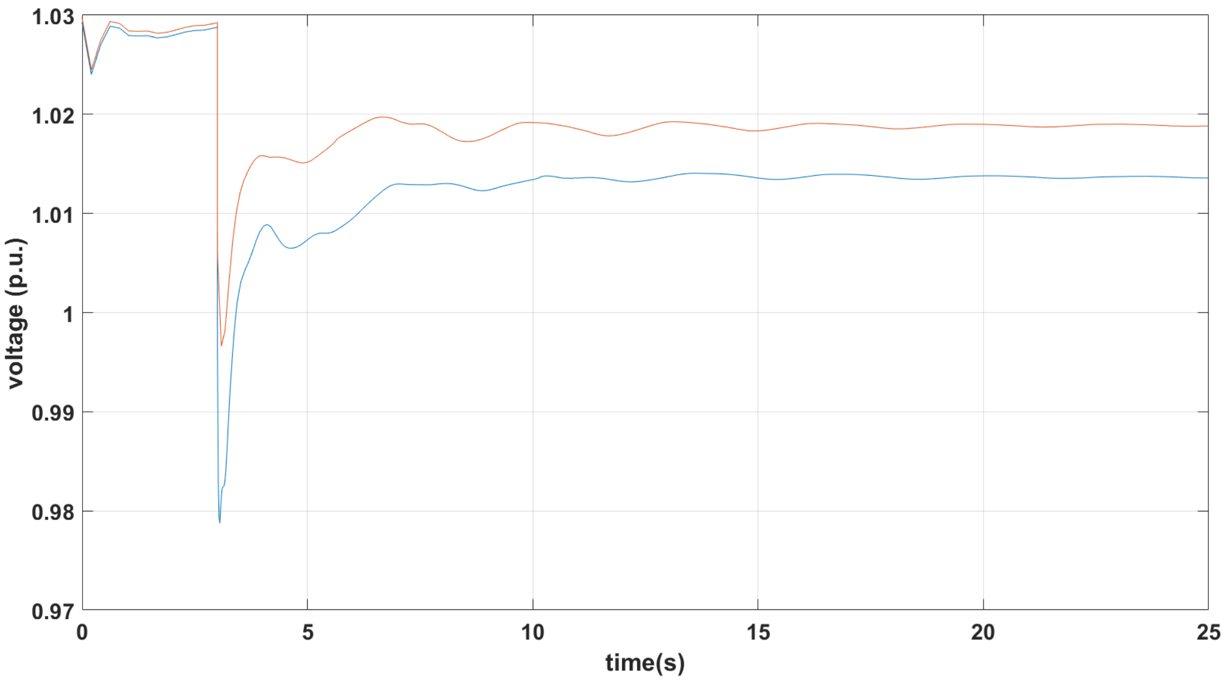


Figure 92. Average bus voltages in Area 26 (LADWP) for the two PDCI contingencies (orange-monopole outage; blue-bipole outage)

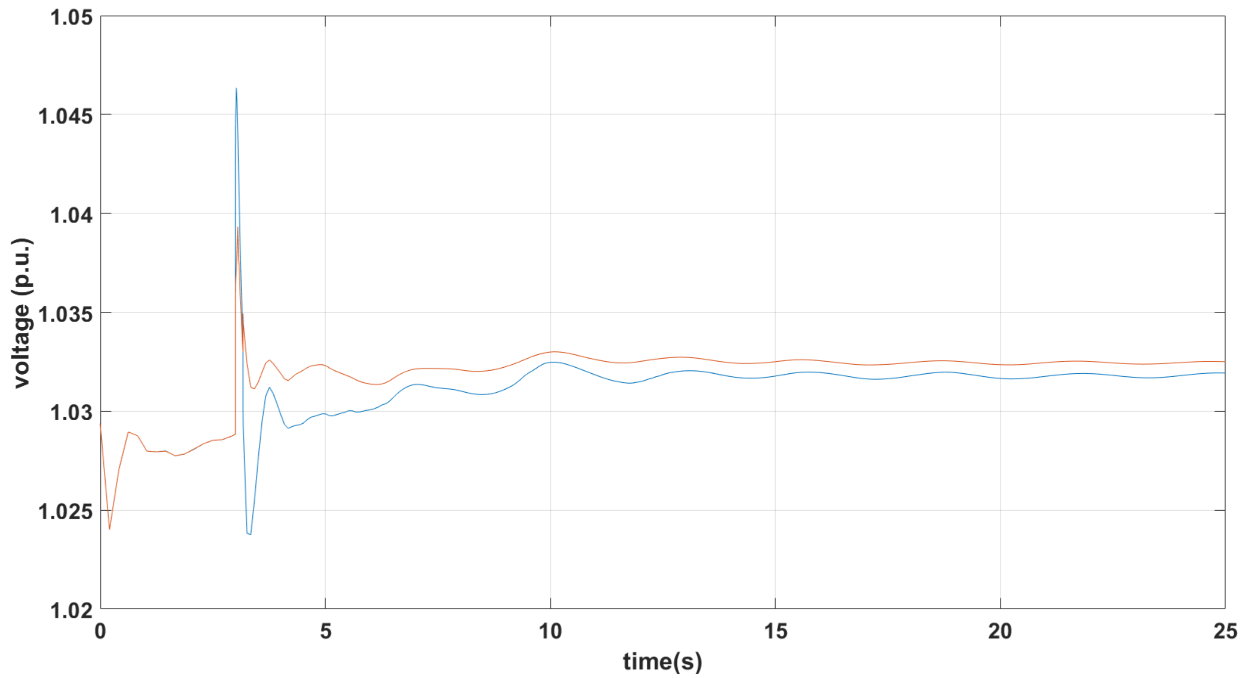


Figure 93. Average bus voltages in Area 26 (LADWP) for the two IPPDC contingencies (orange-monopole outage; blue-bipole outage)

Summary of 2030 Transient Contingency Analysis

The transient contingency analysis performed for the 2030 base case shows that 231 out of 238 or 97% of the transient contingencies result in acceptable transient performance or a stable pos-contingency operating point. Of the remaining 7 contingencies, the violations/instability occurs only for severe contingencies (category P4 and above), although mitigation measures to eliminate the violation/instabilities were found. This suggests that the LADWP power system under the highest bus loading hour of the 2030 SB100 scenario is stable even with less than half of the synchronous generation capacity being online in 2030 base case than in the 2028 case.

Transient Performance Criteria Violations in 2045 Transient Contingency Analysis

When we first performed the 2045 transient contingency analysis, we found that if we allowed the low/high voltage ride-through relays (lhvrt) to trip generation in LADWP when voltages went outside the no-trip region, some in-basin generators that we added were tripping within the duration of the fault. In other words, they were not effectively riding through the fault. As mentioned earlier, it has been noted in a recent NERC report that the region outside the no-trip region in PRC-024-2 should be treated a “may trip” instead of “must trip.” For these reasons, we disabled tripping of generators by the lhvrt relay. The average voltage plots for the transient contingencies in the 2045 base case are shown in Figure 94 through Figure 103.[77]

[77] Please note that the average voltage plots for 4 contingencies are not shown in to as indicated in their titles. These contingencies resulted in unsteady voltages at the end of the simulations. These are plotted separately in Figure 104 to Figure 106. While we were able to find a solution for the P4_11 contingency, we could not find solutions to improve the voltage profiles for the remaining three contingencies. Please see Table 68 for a discussion on these four contingencies.

Only the P5_TAR contingency was found to violate the TPL-001-WECC-CRT-3.1 Criteria. Only the three 34.5 kV Fairfax load buses showed the 70% criterion violation in the TPL-001-WECC-CRT-3.1 criteria.

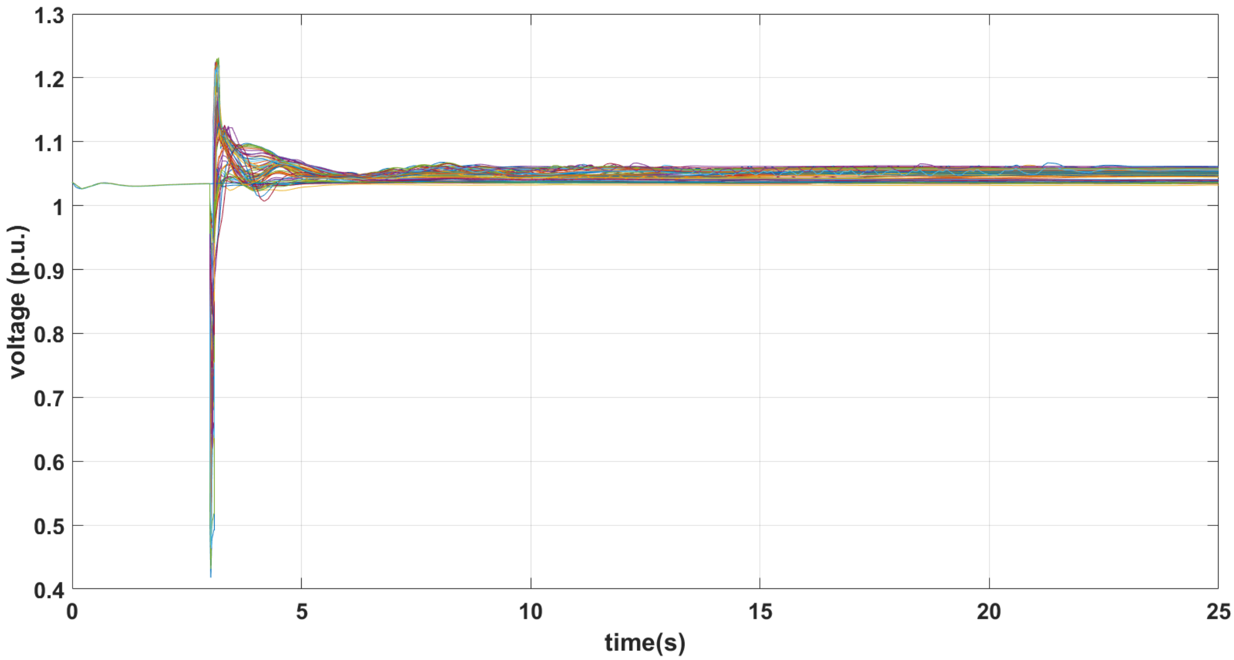


Figure 94. Average bus voltages in Area 26 (LADWP) for all P1 category contingencies

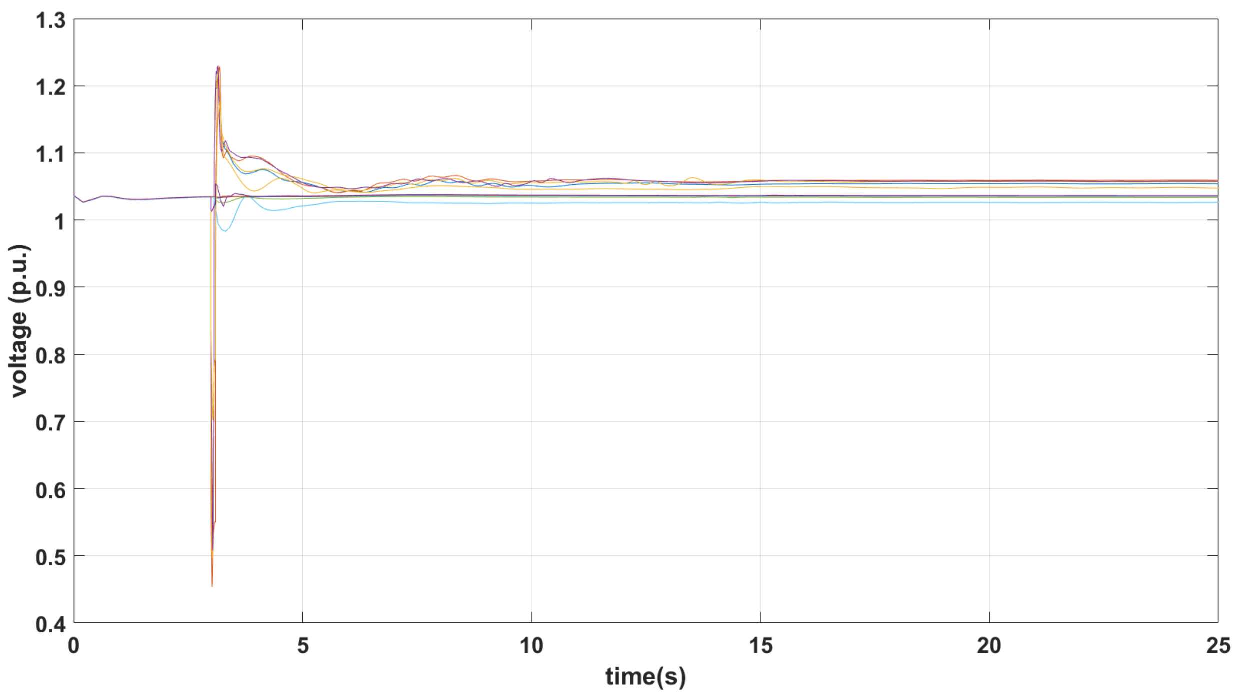


Figure 95. Average bus voltages in Area 26 (LADWP) for all P2 category contingencies

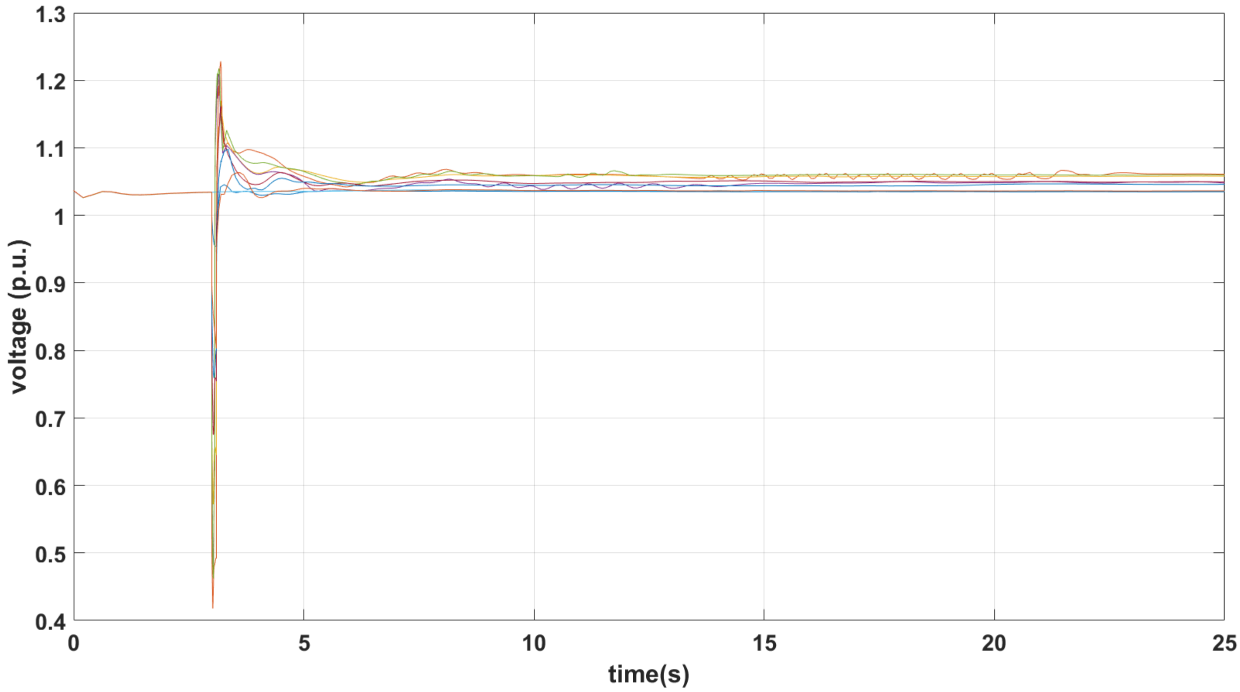


Figure 96. Average bus voltages in Area 26 (LADWP) for all P3 category contingencies

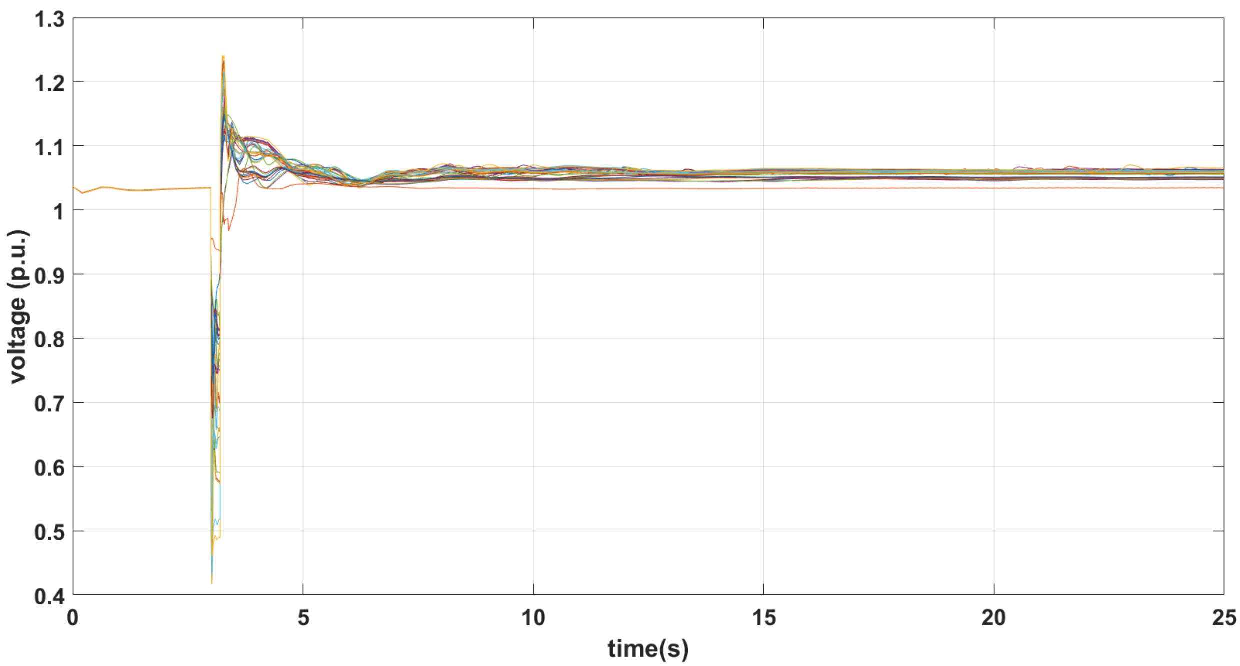


Figure 97. Average bus voltages in Area 26 (LADWP) for all but one P4 category contingencies

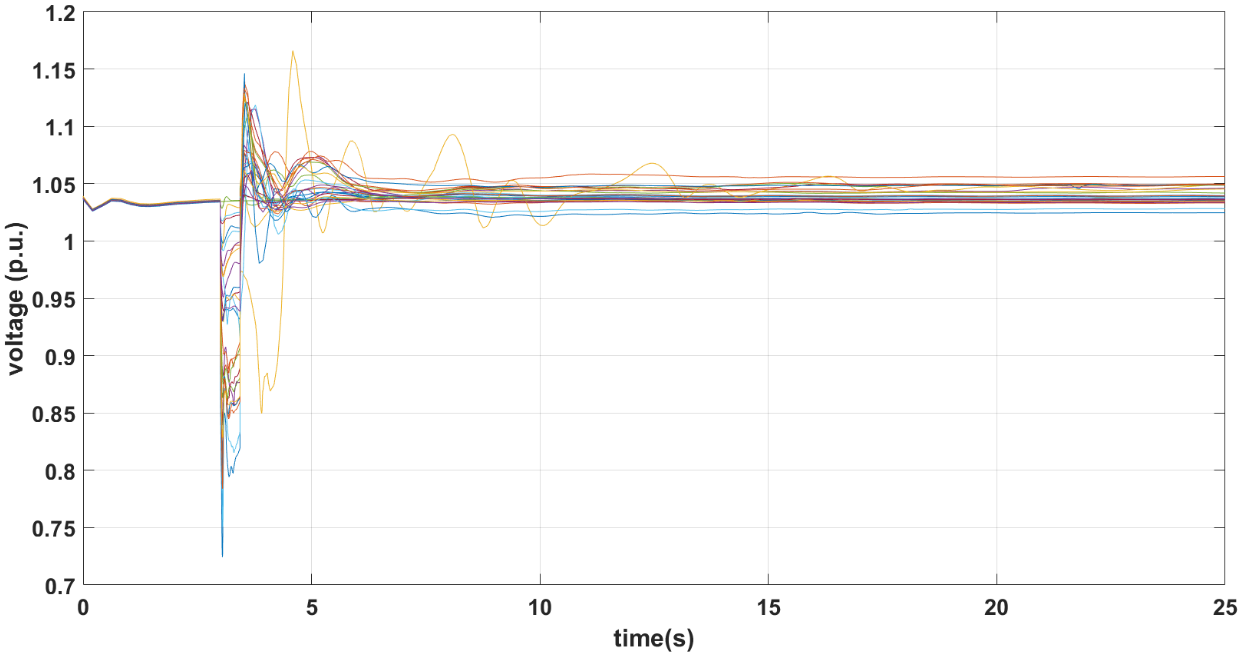


Figure 98. Average bus voltages in Area 26 (LADWP) for all but one P5 category contingencies

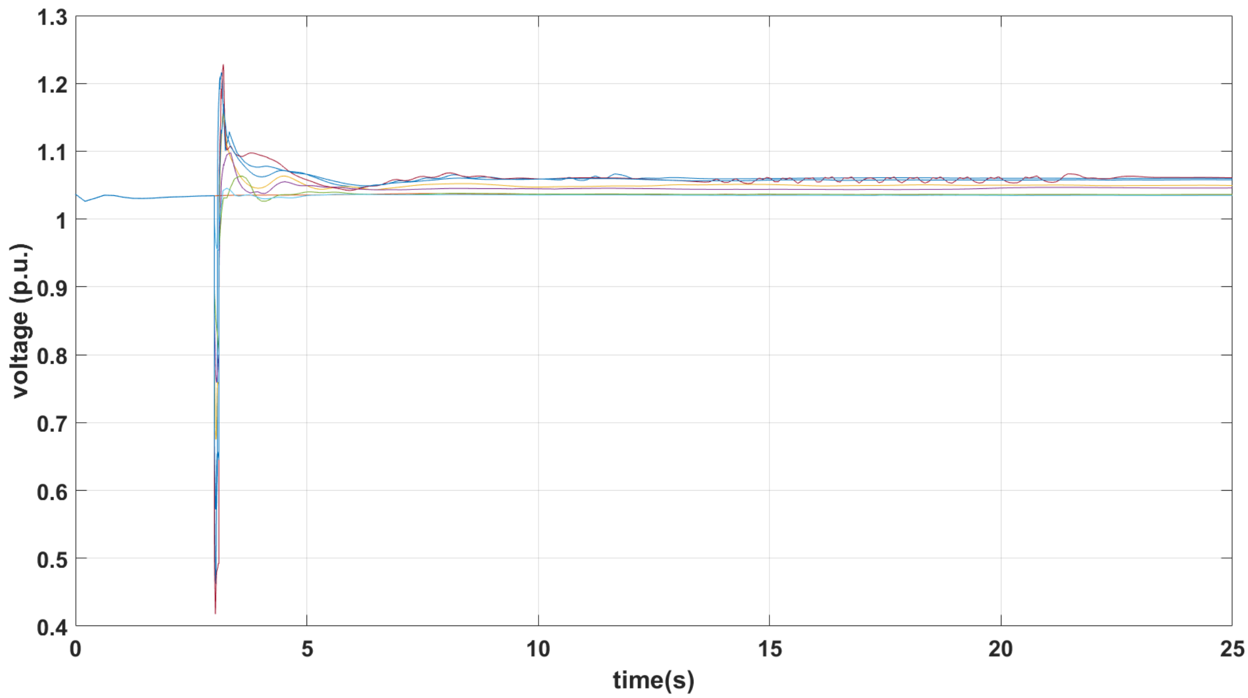


Figure 99. Average bus voltages in Area 26 (LADWP) for all P6 category contingencies

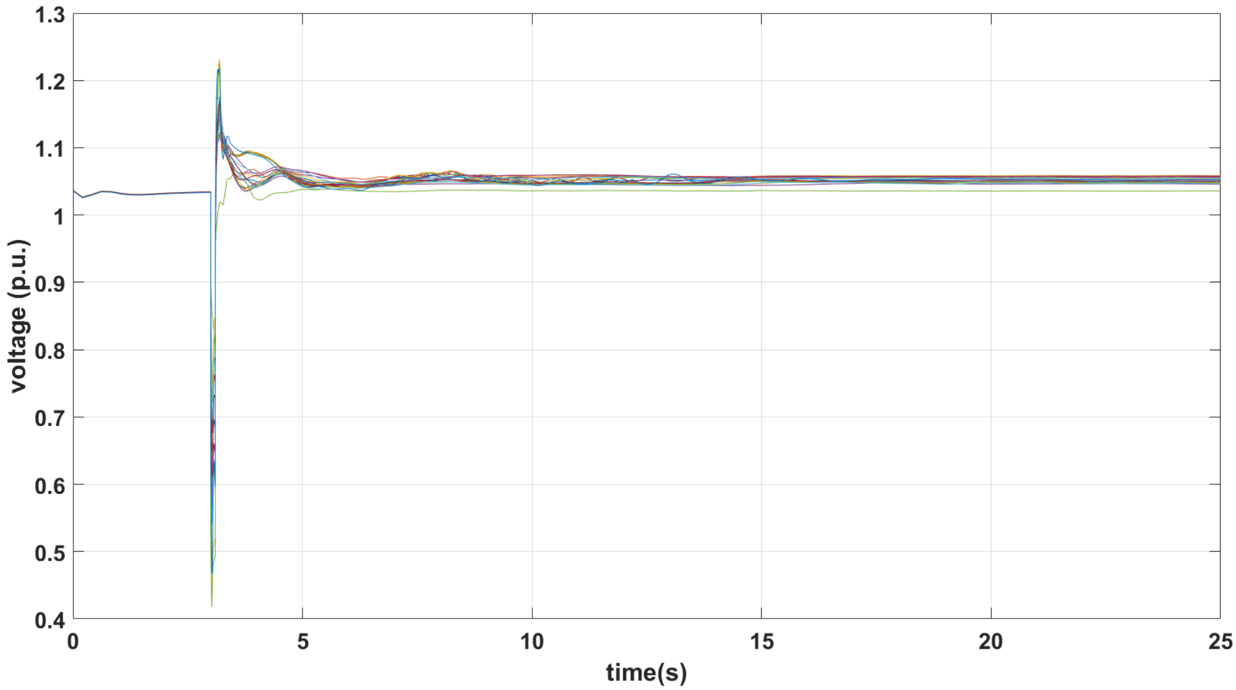


Figure 100. Average bus voltages in Area 26 (LADWP) for all P7 category contingencies

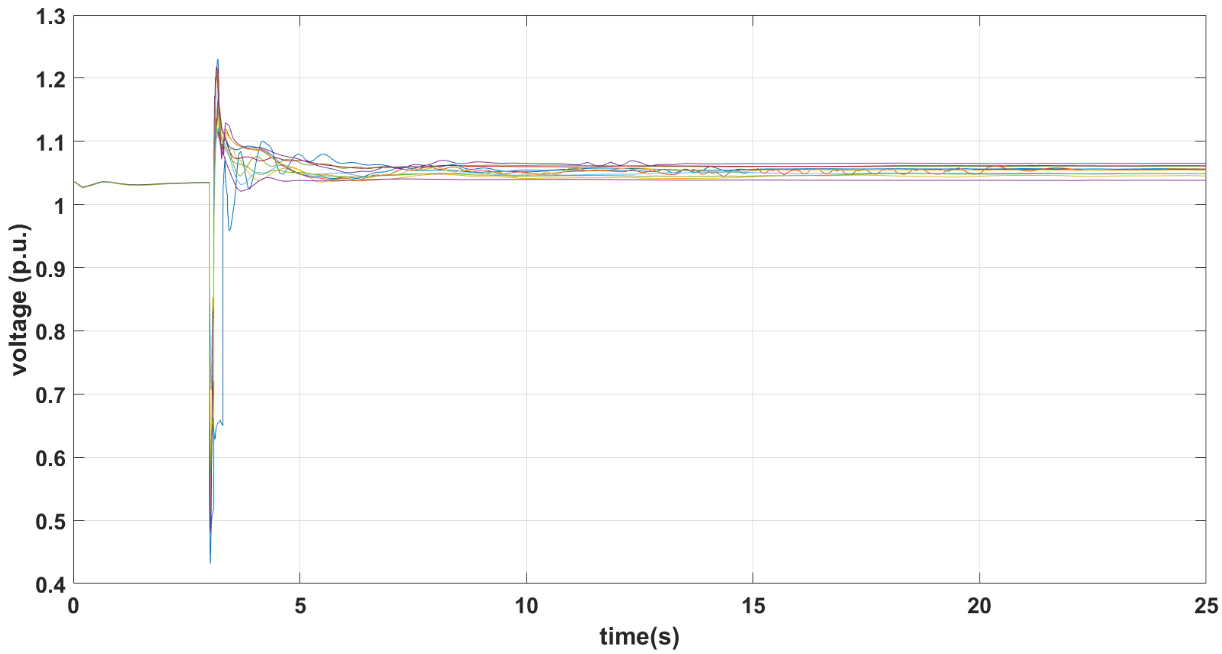


Figure 101. Average bus voltages in Area 26 (LADWP) for all but two extreme category contingencies

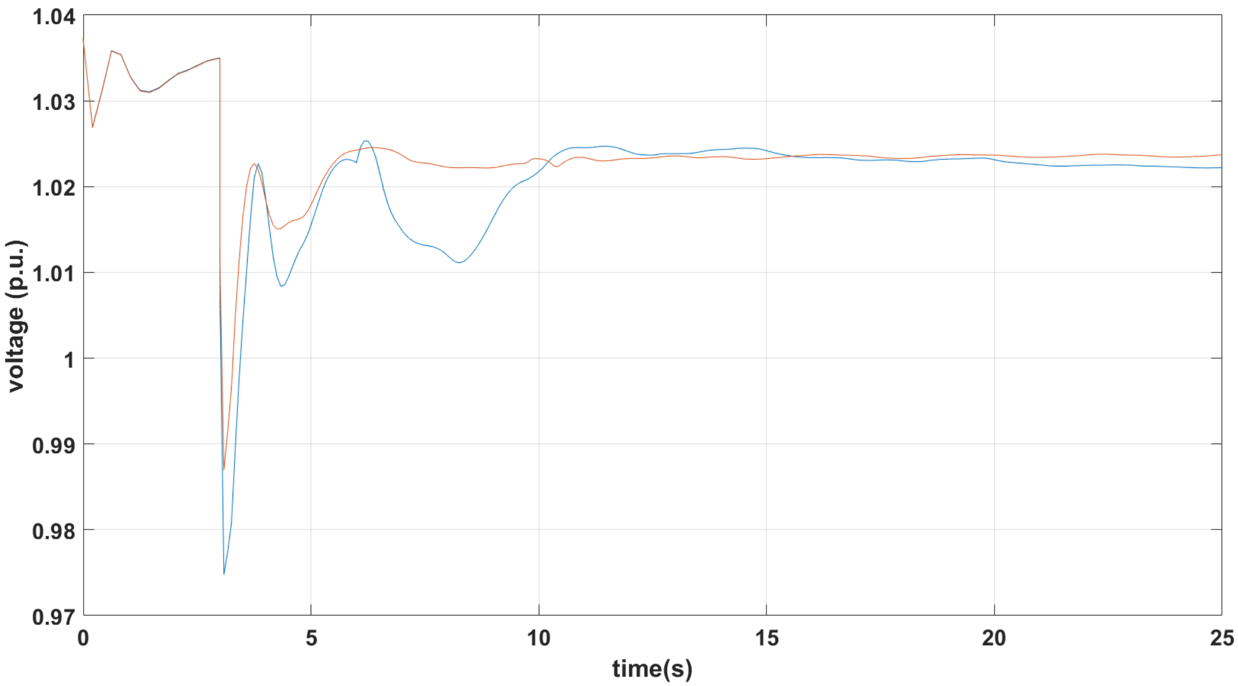


Figure 102. Average bus voltages in Area 26 (LADWP) for the two PDCI contingencies (orange-monopole outage; blue-bipole outage)

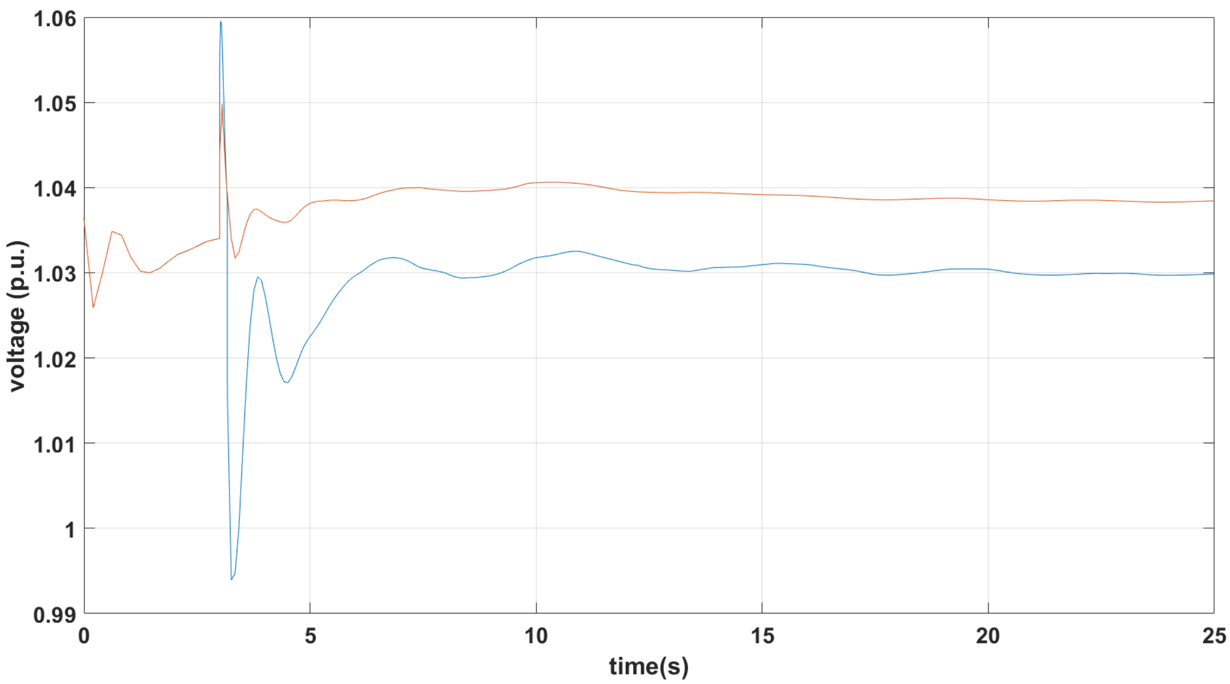


Figure 103. Average bus voltages in Area 26 (LADWP) for the two IPPDC contingencies (orange-monopole outage; blue-bipole outage)

Table 68. Contingencies with Unsteady Post-Disturbance Steady State in the 2045 Base Case

Contingency Number/ Category	Contingency Description	Potential Cause for Post-Disturbance Unsteady Steady State	Potential Solution
P4-11/P4	Three-phase to ground fault on the 500 kV Adelanto Bus which is cleared after 12 cycles (0.2 seconds) and the 500 kV line between Toluca and Adelanto buses is opened	The 500 kV Toluca-Adelanto line is part of the VIC-LA path, which is loaded to 4136 MW in the base case. This line itself carries around 1,600 MW. Removing this line from service likely exceeds the power carrying capacity of the remaining VIC-LA lines resulting in small but sustained voltage oscillations	By reducing the VIC-LA flow to around 3,800 MW (4,136 MW in the 2045 base case), these oscillations were eliminated. The reduction was achieved by increasing Castaic to 600 MW (offline in the 2045 base case) and reducing generation by the same amount at Marketplace and Crystal.
P5-TAR/P5	Single-phase-to-ground fault on the 230 kV Tarzana Bus which is cleared after 26 cycles (0.433 seconds) and Two Tarzana-Rinaldi, One Tarzana-North Ridge, and One Tarzana-Olympic 230 kV lines are opened when the fault is cleared.	Almost 2,000 MW of flow on the lines that are taken out of service in this contingency, which is double the flow on these lines in the 2030 case	Stable performance if all load at the Tarzana buses (318 MW) is tripped (either immediately when the fault is cleared, or few cycles later)
Line-02/Extreme	Three-phase-to-ground fault on the 230 kV Tarzana Bus which is cleared after six cycles (0.1 seconds) and Two Tarzana-Rinaldi, and One Tarzana-North Ridge 230 kV lines are opened when the fault is cleared.	Almost 1,800 MW of flow on the lines that are taken out of service in this contingency, which is double the flow on these lines in the 2030 case	Stable performance if all load at the Tarzana buses (318 MW) is tripped (either immediately when the fault is cleared, or few cycles later)
Line_14/ Extreme	Three-phase fault at the 500 kV Adelanto bus followed by loss of five lines - Adelanto-Toluca 500 kV line, two, 230 kV lines between Valley and Toluca, and two, 230 kV lines between Airway and Rinaldi	Significant power flow on the outage lines, which the remaining system cannot handle.	Stable performance if all load (418 MW) at the Toluca buses is tripped (either immediately when the fault is cleared, or few cycles later)

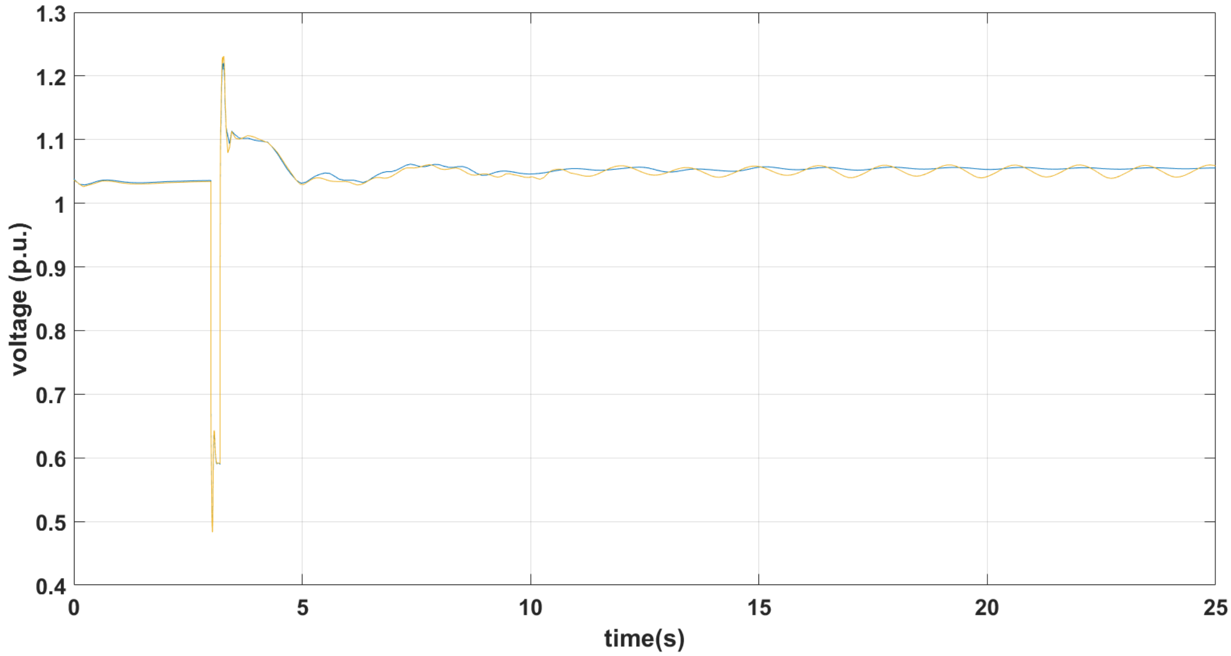


Figure 104. Average bus voltages in Area 26 (LADWP) for the P4-11 contingency

Yellow (with VIC-LA at 4,195 MW). Blue (with VIC-LA at 3,800 MW).

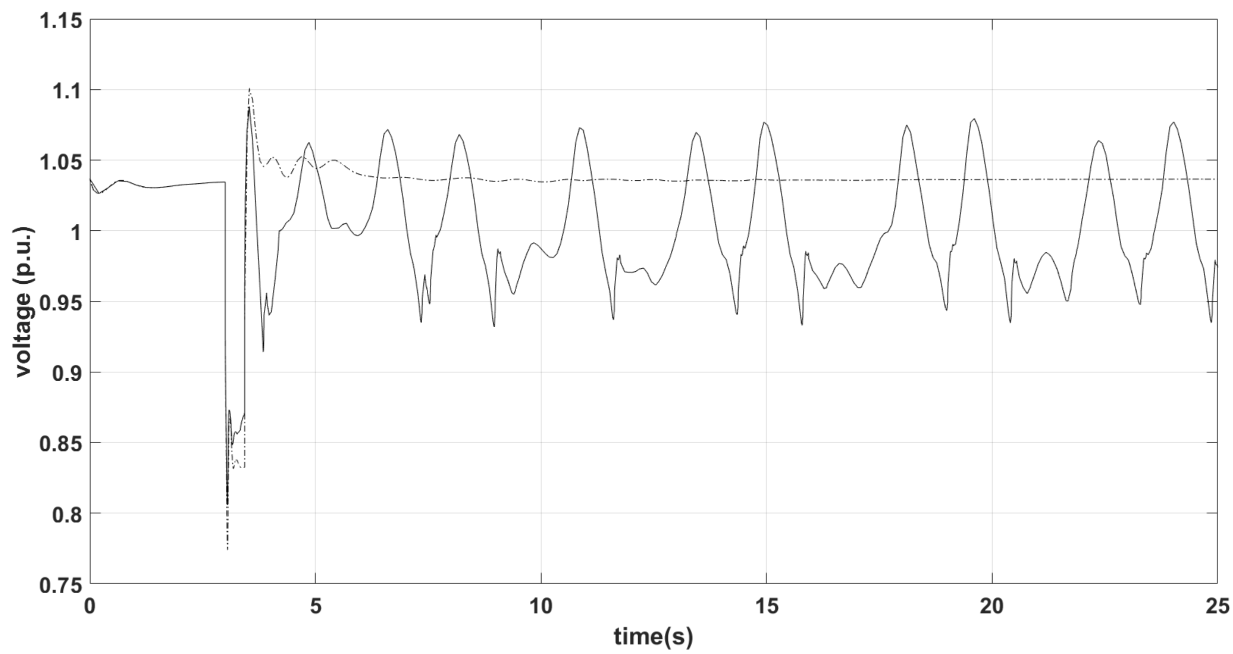


Figure 105. Average bus voltages in Area 26 (LADWP) for the P5-TAR (black) contingency

P5-TAR (black dashed) with Toluca load tripped at fault clearing.

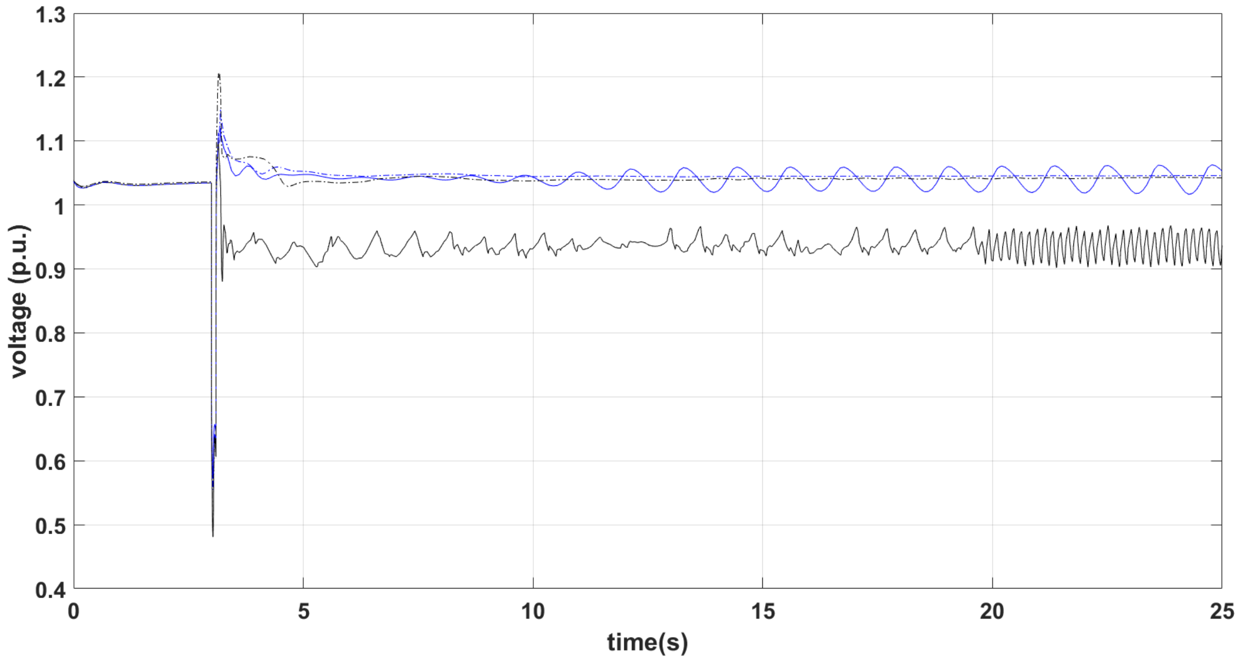


Figure 106. Average bus voltages in Area 26 (LADWP) for the extreme contingencies Line 02 (blue), Line 14 (black), Line 02 (blue dashed) with load at the Tarzana buses tripped after fault clearing, Line 14 (black dashed) with load at the Toluca buses tripped after fault clearing

Summary of 2045 Transient Contingency Analysis

For the 2045 base case, satisfactory transient performance is achieved for 244 of the 248 (or 98%) of the contingencies that were run. Of the remaining four (listed in Table 68), solutions were found for all that would result in a stable post-disturbance steady state.

In summary, the transient performance for both the 2030 and 2045 cases is quite good for over 97% of the contingencies. For the remaining severe contingencies, increased generation in the basin may resolve unsatisfactory performance or instabilities.

E.5 Details of the Power Flow Long-Duration Outage Cases

We selected two most constrained outage scenarios for PSLF feasibility evaluation, which are:

1. Scenario 1: Critical N-1-1 contingency of NRTHRDGE – TARZANA 230 kV line and RINALDI – TARZANA 230 kV line 1 or 2;
2. Scenario 2: NREL-created STS DC lines contingency

The highest bus loading hour for both scenarios is 8/12/45 11:00. We started with the 2045 base case and built these two long-duration outage cases by updating the generation (including distributed generation units) and load of LADWP area, based on the data provided by PLEXOS DC flows.

Table 69 below summarizes the key parameters of the two long-duration outage cases with a comparison with the 2045 base case.

Table 69. Key Parameters of LADWP of the 2045 Base and Two Long-Duration Outage Cases

Parameter	Base	Scenario 1	Scenario 2
In-Basin Load (MW)	7,342	8,505	8,505
Burbank & Glendale (MW)	823	823	823
Aux Load (MW)	175	182	125
Total Load (MW)	8,340	9,510	9,453
Losses (includes PDCI and IPPDC losses; MW)	305	176	186
Total Real Power Demand (including losses; MW)	8,645	9,686	9,639
Bulk Generation (MW)	7,547	6,773	7,446
Distributed Generation (MW)	-619	3,093	2,938
Imports (MW)	1,717	-180	-745
Total Real Power Generation (MW)	8,645	9,686	9,639

Both long-duration outage cases reach the feasible powerflow solutions without any addtional reactive power resources other than the ones already included in 2045 base case.

We do observe pre-contingency violations on one transformer and one transimission line. Details are listed in Table 70.

Table 70. Thermal Violations in Long-Duration Outage Cases Compared to Base or Sensitivities Cases

From Bus #	From Bus Name	From Bus kV	To Bus #	To Bus Name	To Bus kV	Ckt	Line/ Transformer	Highest Loadings in Long-Duration Outages Cases	Highest Loadings in Base or Sensitives Cases
26051	MEAD	287	19012	MEAD S	230	M	Tran	151%	157%
26136	COTTONWD	230	26132	BARRENRD	230	1	Line	119%	153%

According to Table 70, the max-loading percentages of both violations are lower than the existing upgrade requirement identified in the Steady-State Contingency Analysis Results section above (Section E.3). In other words, no additional upgrade requirement was identified for long-duration outage studies.

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