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Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California

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Technical Report
NREL/TP-6A20-64884
January 2016

Contract No. DE-AC36-08GO28308

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Prepared under Task No. WTHF.1000

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Preface

This study was funded by a variety of industry and foundation sources with the goal of understanding the impacts of a low-carbon grid in California. These organizations put together a Steering Committee to assemble the study team and guide the study process. The Low Carbon Grid Study (LCGS) put out three reports: 1) this one on grid operations, 2) an analysis by GE Energy on reliability impacts of the LCGS scenarios (Miller 2015), and 3) a capital cost analysis by JBS Energy of the LCGS scenarios (Marcus 2015).

As experts on renewable energy and energy efficiency deployment in California, the Steering Committee also helped produce the portfolio of renewable energy and energy efficiency technologies that were used as the basis for this study. The study team also assembled a Technical Review Committee, which met throughout the study to review assumptions, methodologies, results, and conclusions. The authors would like to thank the Steering Committee for their support and the Technical Review Committee for lending their time and expertise to improve this study. Although the members of the Steering Committee and Technical Review Committee helped prepare and review this report, this report may not reflect the specific views or interpretations of any member of either committee. Jim Caldwell led the Steering Committee, and the Center for Energy Efficiency and Renewable Technologies was the fiscal sponsor.

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The authors would also like to thank Jim Turnure and the Energy Information Administration for support for this study, and Trieu Mai, Paul Denholm, Dave Corbus, Liz Anthony, Nick Miller, and Bill Marcus for their help.

Executive Summary

The California 2030 Low Carbon Grid Study (LCGS) analyzes the grid impacts of a variety of scenarios that achieve 50% carbon emission reductions from California's electric power sector. Impacts are characterized based on several key operational and economic metrics, including production costs, emissions, curtailment, and impacts on the operation of gas generation and imports. We used the PLEXOS model to simulate the unit commitment and dispatch of the generating fleet in the western United States for 23 different scenarios, which included a variety of assumptions regarding the generator portfolios, energy efficiency, storage, and grid flexibility. A focus of the study is the impacts of electric system flexibility measures on key operational and economic metrics. The LCGS study comprises three reports: 1) this NREL report on the operational impacts of a low-carbon grid, 2) a report by JBS Energy on the capital costs of the scenarios (Marcus 2015), and 3) a report by GE Energy on the dynamic grid issues caused by high renewable penetrations (Miller 2015).

Portfolios and Major Assumptions

The portfolios (Figure ES-1) for this study are:

- **Baseline**: Assumes prior renewable portfolio standard (RPS) legislation (33% by 2020) and energy efficiency projected by the California Energy Commission (CEC) (this scenario has 36% renewable penetration[1] and 340 TWh annual load).
- **Target**: Achieves LCGS goal of 50% carbon reduction by 2030 using a higher level of energy efficiency and a diverse mix of renewable resources (56% renewable penetration[1] and 320 TWh annual load). This Target portfolio includes 2.2 GW additional storage.
- **High Solar**: Assumes the same quantity of renewables, storage, and load as Target but with a less diverse mix of resources: more photovoltaics (PV) and less wind, concentrating solar power (CSP), biomass, and geothermal (56% renewable penetration[1] and 320 TWh annual load).

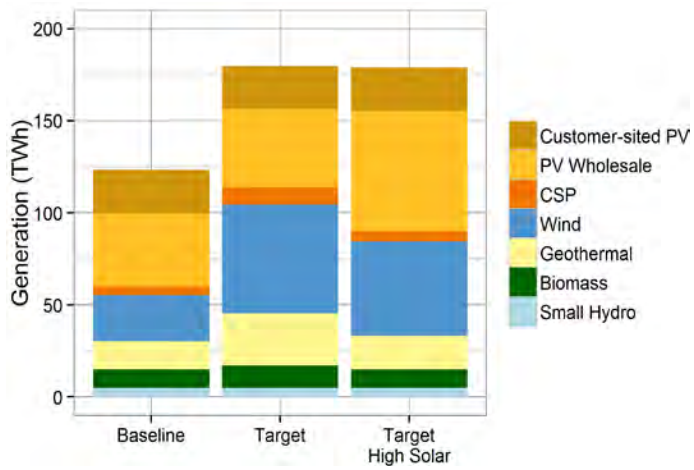

Figure ES-1. Renewable generation in LCGS portfolios

All portfolios include 23 TWh of rooftop or customer-sited PV penetration (7% of annual load).

In order to understand how changes in operational practices could impact the flexibility of the system, we created the two grid flexibility frameworks listed in Table ES-1. These assumptions (and others) were tested in various combinations with the portfolios.

[1] Renewable percentages include rooftop PV and are a fraction of total California load plus transmission losses, which differs from current RPS calculations.

Table ES-1. Conventional vs Enhanced Flexibility Assumptions

Conventional Flexibility	Enhanced Flexibility
70% of out-of-state (CA-entitled[2]) renewable, nuclear, and hydro generation must be imported	Only physical limitations on imports and exports
25% of generation in California balancing authorities must come from local fossil-fueled and hydro sources	No minimum local generation requirements
1.5 GW battery storage to meet CA Public Utility Commission requirement in addition to existing storage	In addition to the existing storage and 1.5 GW mandated battery storage, 1 GW new pumped hydro, and 1.2 GW new out-of-state compressed-air energy storage that are only added in the Target and High Solar portfolios, as noted above.
Limits on ability of hydro and pumped storage for providing ancillary services[3]	Less strict limits on hydro and pumped storage for providing ancillary services

By not enforcing the conventional flexibility constraints, the enhanced flexibility scenarios increase California's ability to export California-entitled energy, shut down gas generation to make room for renewables and use storage to reduce curtailment and peak-load energy needs. The conventional flexibility assumptions are not intended to be an exact replica of today's operating conditions (see Table ES-3 for differences), and the modeling assumptions are not policy recommendations but proxy representations of potential operating conditions based on recent proposals and policies.

Key Findings

- California can achieve a 50% reduction in CO_2 levels by 2030 in the electric sector under a wide variety of scenarios and assumptions (Figure ES-2). Conventional grid flexibility assumptions and the less diverse portfolio (High Solar) led to 14% more carbon emissions than the more diverse Target portfolio with enhanced flexibility. The Baseline portfolio shows significant reductions in carbon compared to today due to more PV generation (under the 33% RPS) and the retirement of California-entitled coal generation outside California. The only scenario that did not achieve a 50% reduction had conventional grid flexibility and dry hydro assumptions.

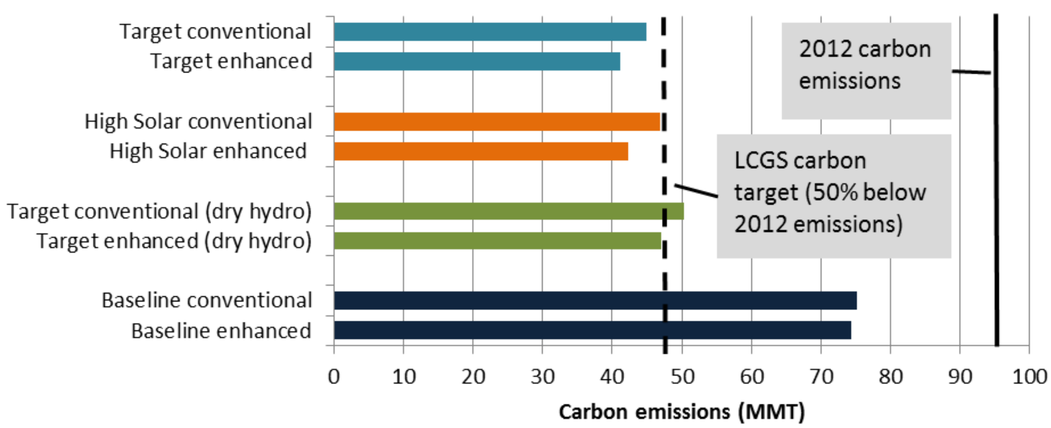

Figure ES-2. Carbon emissions (MMT) in eight selected LCGS scenarios

[2] CA-entitled refers to generation that is owned by or contracted to California utilities but located out of state.
[3] Ancillary service limitations were tuned so that ancillary service provisions were similar to 2013 in CAISO.

- The energy efficiency and renewable energy additions reduce production costs by $4.85 billion in the model with enhanced flexibility (see Table ES-2). The conventional grid flexibility assumptions increase production costs by $65 million in the Baseline and $550 million in the Target scenario. The model shows the cost reduction of enhanced flexibility is much higher in scenarios with high penetration of renewables.

Table ES-2. Reduction in Production Cost Compared to Baseline Enhanced

Portfolio	Conventional flexibility	Enhanced flexibility
Baseline	-$65m	0
Target	$4,300m	$4,850m

- For comparison, a companion report by JBS Energy (Marcus 2015) found that the annualized capital costs of the incremental renewable generation, transmission, and storage capacity between the Target and Baseline portfolios was $5.1 billion, or about $230 million more than the production cost reduction from the Target portfolio. This cost difference represents 0.6% of the annual revenue requirement for California utilities. Depending on technology costs, economic conditions, natural gas, and carbon prices, the overall (capital and production costs) cost impact of the Target scenario with enhanced flexibility (compared to the Baseline scenario) ranges from -3% to 6% of the annual revenue requirement for California utilities.

- Curtailment of renewable generation is much lower in the enhanced flexibility cases (<1%) than the conventional flexibility cases (up to 10%); see Figure ES-3. The level of grid flexibility can be as significant as the portfolio in driving curtailment: the Baseline conventional scenario has higher curtailment (0.6%) than the Target enhanced (0.2%). The modeling indicated that the combination of the import rule and local generation rule drives curtailment in the conventional grid flexibility assumptions although each of these assumptions alone has only modest impact on the results. In the scenarios with conventional flexibility, diversity of renewable resources led to lower costs and emissions.

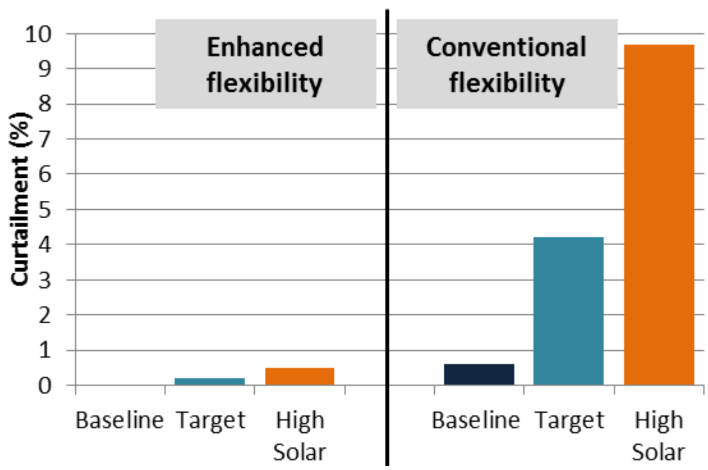

Figure ES-3. Curtailment in six selected LCGS scenarios

- The enhanced operational flexibility options tend to increase cycling at California gas generators; storage and demand response can help reduce emissions and curtailment while reducing cycling.

- Imports from fossil-fuel generation are reduced from today's levels in the Baseline scenario due to out-of-state coal retirements and in-state PV generation. Imports from out-of-state renewable generation in the Target scenarios replace imports from fossil fuel generation in the Baseline scenario.

- Achieving high levels of renewable penetration in the rest of the western United States does not change the key conclusions on curtailment, emissions, and production costs in California based on the optimal west-wide dispatch modeled. Achieving enhanced levels of flexibility may be more difficult if neighboring states will not purchase California-entitled generation even when that is the lowest-cost option.
- Flexibility comes from a wide variety of sources. During the steepest hourly ramp of the year in the Target enhanced flexibility scenario, the primary resources ramping to meet the 11 GW hourly ramp include physical imports (4.5 GW ramp), storage (3.2 GW), the gas fleet (3.2 GW), and demand response (0.2 GW). Other high-ramp hours have different combinations of those resources contributing to serve the ramp, often including hydro generation.
- GE Energy examined the dynamic grid issues associated with the LCGS scenarios. Miller (2015) found that California should be able to procure enough frequency response from renewable generation, demand-side participation, and energy storage to meet obligations without curtailing additional renewable generation. Transient stability could present risks in the LCGS scenarios, although mitigation options (e.g., synchronous condensers, transmission) do exist today. More detailed modeling of low-carbon scenarios will be needed to fully assess these risks.

Comparison with Today's Grid and Sensitivities Analyzed

Some key differences exist between today's grid and the assumptions used in the conventional flexibility grid framework. These differences are shown in Table ES-3 (more detail in report):

Table ES-3. Key Differences Between Today and Conventional Flexibility Assumptions for LCGS

Difference	Impact
Model assumes optimal west-wide dispatch subject to constraints and hurdle rates	In reality, bilateral contracts and other market inefficiencies can lead to out-of-market dispatch and possibly more significant integration impacts of renewables.
Diablo Canyon nuclear generating station is assumed to retire	Diablo Canyon is a zero-carbon resource that would make hitting a carbon target easier, but could increase integration challenges.
3 million electric vehicles adding 13 TWh of load	Half of the vehicles are assumed to be optimally charged, creating the potential for up to 3,000 MW of load during times of curtailment.
Non-renewable generation fleet changes include coal retirements outside California	Coal retirements and gas-fleet changes are taken from Western Electricity Coordinating Council and CA Independent System Operator projections. Combined heat and power facilities are assumed to have some operational flexibility, per CA Public Utilities Commission policy.
Transmission is added in the Target portfolio to bring renewable resources to load	This includes a north-south line from Idaho to southern Nevada that helps relieve north-south congestion and improves ability to use resource diversity throughout the west. Scenarios produce larger intertie flow changes than seen historically in some cases.
Rooftop PV generates 24 TWh in all scenarios (7%–8% of total annual generation)	The Baseline and Target portfolios both include 24 TWh of rooftop PV generation, which reduces emissions compared to today in both portfolios.

Model scenarios in this study examined various types of flexibility differences, including:

- Resource investments: Diverse (Target) compared to high solar (High Solar) portfolios with and without additional storage
- Operational or institutional changes: Physical import requirements, local generation requirements, ancillary service provision limitations on hydro resources, and real-time flexibility in import schedules (e.g., due to an efficient energy imbalance market)
- Demand-side flexibility: Higher levels of demand response (optimal or utility-influenced charging of half of electric vehicles is included in all scenarios)

In addition to scenarios with various combinations of these assumptions (including the conventional and enhanced flexibility scenarios), we also modeled scenarios with higher west-wide renewable penetrations, lower gas prices, higher CO_2 prices, and different hydro resource levels.

Conclusion

The modeling results indicate that achieving a low-carbon grid (with emissions 50% below 2012 levels) is possible by 2030 with relatively limited curtailment (less than 1%) if institutional frameworks are flexible. Less flexible institutional frameworks and a less diverse generation portfolio could lead to higher curtailment (up to 10%), operational costs (up to $800 million higher), and carbon emissions (up to 14% higher).

Future work should examine issues related to bilateral contracts and other sources of market friction and what can be done to limit any impact that these institutional barriers could present to a low-carbon grid. Also, further work is needed to understand stability impacts of a low-carbon grid and ways to cost-effectively mitigate these potential issues.

List of Associated Publications

Grid modeling: Brinkman, G., J. Jorgenson, J. Caldwell, A. Ehlen. *Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California*. National Renewable Energy Laboratory. 2015.

Capital cost analysis: Marcus, B. *Low Carbon Grid Study: Comparison of 2030 Fixed Cost of Renewables and Efficiency, Integration with Production Cost Savings*, JBS Energy, 2015.

Dynamic reliability analysis: Miller, N. *Low Carbon Grid Study: Discussion of Dynamic Performance limitations in WECC*, GE Energy Consulting, 2015.

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1 Introduction

California is a global leader in the transition to a low-carbon grid; low-carbon generation technologies and energy efficiency are being deployed significantly, and state policies will lead to continued growth of these technologies. California Executive Order S-03-05 targets a reduction in greenhouse gas emissions within or attributable to the state of California to 80% below 1990 levels by 2050. Analysis of the 2050 target demonstrates that the electricity sector plays a crucial role in achieving this target. In fact, the electric power grid must almost completely decarbonize, as well as bear a higher burden of total end-use energy consumption in California (Williams et al. 2012). Significant electrification of the transportation sector and building space conditioning are also key elements in achieving the long-term target. The motivation of this study was to analyze the ability of California's electric sector to reduce carbon emissions to levels that are on the path to the 80% reduction by 2050.

Since originally established by the California legislature in 2002, the state's renewable portfolio standard (RPS) required that California's electricity providers procure a percentage of their total electricity from eligible renewable resources. In 2015, California passed State Bill No. 350, which increases the RPS from 33% by 2020 to 50% by 2030. SB 350 also codifies a goal to establish an interim target for reducing greenhouse gas emissions from 1990 levels by 40% (within all sectors) by 2030.

At the renewable penetration levels studied here (50% or greater), specifying that a certain amount of renewable resources must be procured is not sufficient to ensure that carbon targets are met efficiently. The composition of that renewable portfolio, the nature of the other half of the energy supply, and changes to historic practices and the institutional framework of grid planning and operations are key to cost-effectively maintaining reliability while achieving the greenhouse gas reduction targets that motivate the procurement of renewable resources. This study attempts to analyze a low-carbon grid and understand what changes to operational and procurement practice and enabling technologies (such as storage, demand response, a more nimble gas fleet) might help to efficiently integrate a low-carbon portfolio.

Previous studies examined scenarios relevant to carbon levels being considered for legislation in the 2030 timeframe (e.g., 50% carbon reduction). Several key studies have been performed by the California Independent System Operator (CAISO), Energy+Environmental Economics (E3), and the Union of Concerned Scientists (UCS). These studies are important steps toward understanding potential challenges and solutions for integrating enough low-carbon technologies to reach goals of 50% reduction from 2012 CO_2 levels by 2030.

The California ISO's 2014 Long-Term Procurement Plan (LTPP) deterministic study was based on the 2014 California Public Utilities Commission (CPUC) LTPP process (Liu 2014). This study looked at a number of different scenarios that meet the existing 33% RPS, and two scenarios that studied a potential 40% RPS. The simulations primarily assume there are no major changes in the institutional framework of the system (e.g., no net exports allowed, most California-entitled[4] out-of-state renewable generation must be imported in each hour). The "Expanded Preferred Resources" scenario was a 40% RPS scenario with the highest levels of

[4] CA-entitled refers to generation that is owned by or contracted to California utilities but located out of state.

projected energy efficiency and behind-the-meter solar photovoltaics (PV) of all the scenarios. This scenario had the lowest carbon emissions; CO_2 emissions were 20 million metric tons (MMT) lower than the "Trajectory" scenario, which was a 33% RPS scenario. Annual curtailment was 6.5% of the renewable energy production that could have been generated absent the modeled constraints in the "Expanded Preferred Resources" scenario. This magnitude of possible curtailment indicates the challenges of integrating a portfolio with a majority of renewable energy coming from solar PV without any changes to the operational practices of a system.

The E3 report, *Investigating a Higher Renewables Portfolio Standard in California*, explored some of the potential operational impacts of a solar PV-dominated renewable grid (E3 2014). The "50% Large Solar" scenario was the primary scenario studied. This scenario exhibited 8.9% curtailment and additional costs associated with renewable curtailment. E3 also found that using a more diverse portfolio, enhanced regional coordination, or demand response and storage could reduce curtailment to 3%–4%.

The UCS report, *Achieving 50 Percent Renewable Electricity in California*, analyzes 33%, 40%, and 50% RPS scenarios using the same base PLEXOS dataset as the CAISO LTPP 2014 study (Nelson and Wisland 2015). Curtailment of renewable resources in the diverse portfolio studied was 4.8% for the 50% RPS Base scenario for the CAISO footprint. Demand response, storage, allowing exports, and allowing renewables to provide reserves were all shown to reduce curtailment. Reducing minimum generation levels of natural gas units also reduced simulated curtailment, but other forms of natural gas generator flexibility (e.g., ramp rate, start times) had little impact on curtailment.

The Low Carbon Grid Study (LCGS) analyzes the impacts of a low-carbon grid on grid operations. We performed analysis on a comprehensive suite of scenarios to understand the impact of specific technologies and operating strategies. The focus of the study was on cases that can successfully and efficiently integrate low-carbon technologies. We also studied scenarios where the combination of portfolio and operating practices made grid operations and integration of renewables less efficient (e.g., higher costs and curtailment close to 10%). These scenarios created an interesting comparison to the less challenging scenarios and also the ability to compare with scenarios from previous studies, such as the CAISO and E3 work.

In this study, we analyzed some of the issues leading to increased curtailment and the associated impacts using a number of different changes to the assumptions. To do this, we needed to have a detailed representation of California's power system and a simpler representation of the rest of the Western Interconnection. This helps us understand how California-owned generation may be sold out-of-state in scenarios where that is allowed, and how higher renewable penetrations in response to policies—such as the Environmental Protection Agency (EPA) Clean Power Plan requirements—may change the ability for California to sell power. We model nodal transmission congestion in California and zonal limits outside of California, with unit-level representation of all generators in the Western Interconnection. We model full representation of forecast error in the unit-commitment modeling and also modeled some of the scenarios with 5-minute time resolution to ensure that the hourly representation was similar to the sub-hourly for all of the resulting metrics of interest (e.g., production cost changes, curtailment, carbon emissions, imports, and gas fleet utilization). More detail on the 5-minute modeling is provided in the Appendix.

This analysis focuses on the impacts of a variety of assumptions, some of which are proxy variables to represent operating practices or policies that cannot be easily modeled in a production cost modeling framework. This study is not intended to be a detailed reliability analysis of the California electric power system. The production cost modeling framework is good for informing policy decisions and understanding comparisons between scenarios, but there are differences between the model and reality, and modeled outputs may differ from reality. One of the key differences is bilateral contracts for generation and transmission, which are not represented directly in the model. The analysis presented in this paper is a detailed operational analysis, and it does not consider capital costs.

This study is intended to inform a companion study by JBS Energy that does perform capital cost and other analyses considering the annual operational cost impacts modeled here. Another companion report from GE Energy Consulting discusses dynamic issues on the grid and how a low-carbon future could impact those issues. For example, the impacts of the large percentage of inverter-based generation on inertia and frequency response are discussed. The LCGS includes this paper, the JBS Energy report on cost impacts (Marcus 2015), and the GE Energy Consulting report on dynamic impacts of a low-carbon grid (Miller 2015).

The LCGS selected scenarios to help understand the impact of specific assumptions in detail to help inform policymakers. The flexibility of the grid has a very significant impact on the effectiveness and efficiency of a low-carbon grid future. Curtailment can range from 0% to 10%, depending on the portfolio of generation and the institutional framework. Associated production costs can vary by close to $1 billion per year (about 10% of California production costs) and California carbon emissions by almost 8 MMT CO_2 per year (20% of California emissions) in the low-carbon grid scenarios depending on the flexibility and portfolio assumptions with identical available renewable resource levels.

2 Scenarios

2.1 Portfolios

Three main portfolios for the California generation fleet in 2030 were developed for study: Baseline, Target, and Target High Solar. The Baseline portfolio represents a continuation of California's current policies, including the 33% RPS and the CPUC storage mandate (CPUC 2013). The Target and Target High Solar portfolios were constructed to achieve electric-sector emissions reductions, assuming that California's policy environment by 2030 was more aggressive on emissions reduction and clean energy than it was in 2014. Both of these portfolios include more clean-energy resources (including energy efficiency) than the Baseline portfolio, but with different renewable resource mixes. The Target and Target High Solar portfolios were built to achieve a certain carbon emissions level (50% below 2012 levels), rather than to represent or suggest a certain RPS target.

2.1.1 California Portfolio Overview

Figure 1 is a graphical representation of the portfolios in the three cases (Baseline, Target, and Target High Solar). Table 1 shows the penetrations of various technologies as a percentage of total load (which includes transmission and distribution losses). The Target case is a more balanced buildout, with most of the increase in energy from the Baseline coming from wind and geothermal. The Target High Solar case adds mostly solar PV generation and out-of-state wind to create a case with about 28% solar (as a percentage of total load), whereas the Baseline and Target portfolios have about 20% solar. The Target case has similar levels of PV, wind, and other resources (20%, 18%, and 17%, respectively), whereas the High Solar case is a 28%, 16%, and 13% mixture of PV, wind, and other resources. These penetrations are for total possible renewable generation (pre-curtailment). Curtailment in the scenarios is not replaced with additional renewable generation; scenarios with more curtailment will have lower renewable penetrations and higher emissions than scenarios with less curtailment.

The total load is about 20 terawatt-hours (TWh) lower in the Target and High Solar portfolios due to the additional energy efficiency compared to the Baseline, which explains why some technologies (e.g., small hydro) have higher penetration levels in the Target portfolios in Table 1 compared to the Baseline even though the generation remains constant. A more detailed table with renewable resource for each type and balancing authority is available in the Appendix.

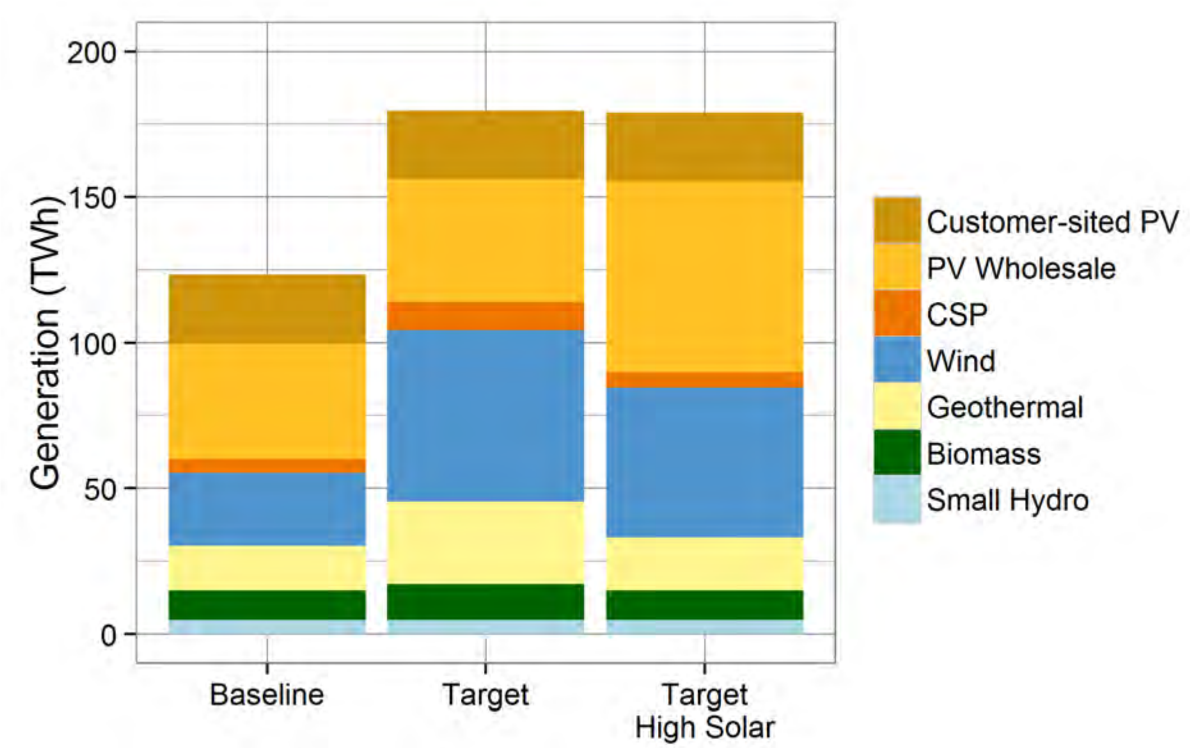


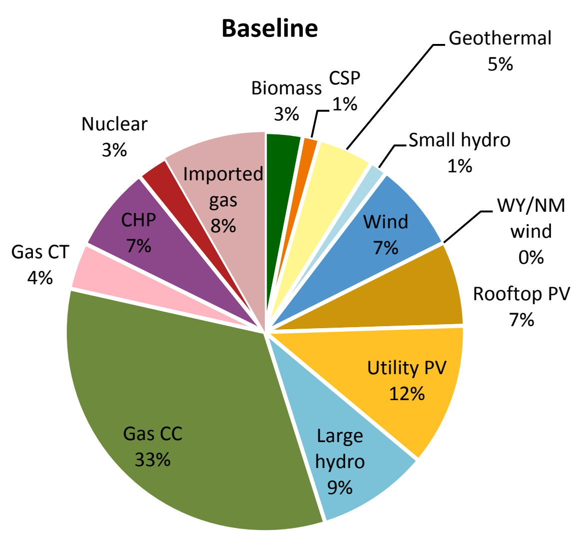
Figure 1. Breakdown of CA renewable generation (pre-curtailment) in LCGS portfolios

Table 1. Penetration by Energy of Renewable Generation (as a fraction of California load)

Technology	Baseline	Target	High Solar
Customer-sited PV (%)	7	6	6
Utility PV (%)	12	15	22
Concentrating Solar Power (%)	1	3	2
Wind in CA (%)	7	12	12
Wind in WY/NM (%)	0	6	4
Biomass (%)	3	4	3
Geothermal (%)	5	9	6
Small hydro (%)	1	1	1
Total* (%)	**36**	**56**	**56**

* Note that these totals do not represent calculations based on RPS legislation (which has specific rules related to customer-sited PV and certain types of load). It is the percentage by energy of the total annual California load, including losses.

Figure 2 shows the distribution of generation sources for the California generation in the three portfolios. The exact distribution of technologies dispatched depends on the specific scenario and assumption, so the distribution of imported and local gas generation is approximate, whereas the renewable portfolios are based on possible generation in these charts (assuming no curtailment). More details regarding the portfolio assumptions are discussed later in this section.



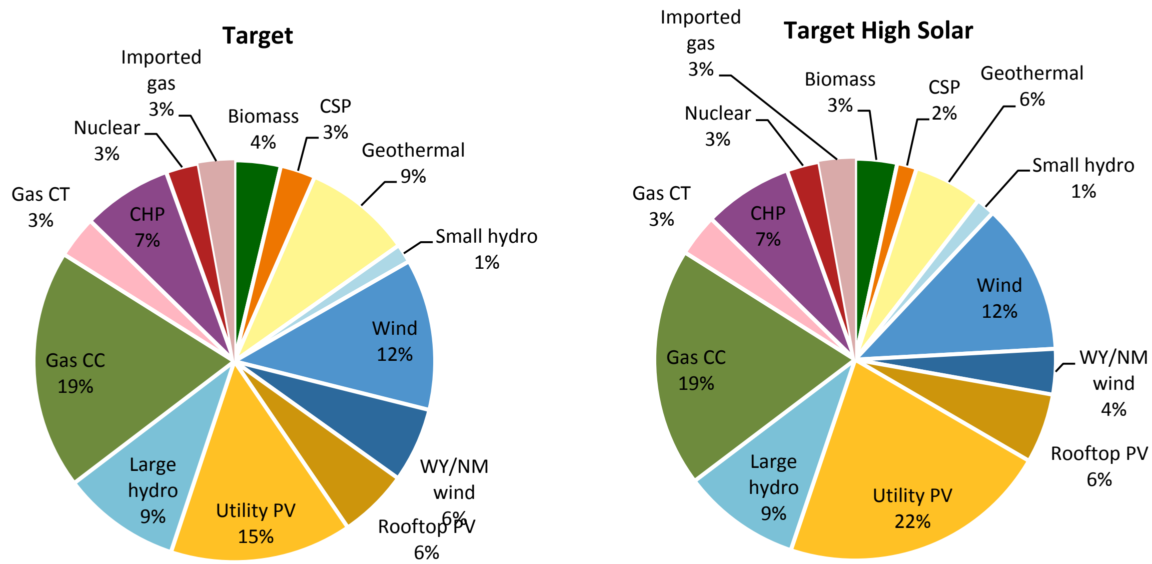


Figure 2. Total California generation and imports in LCGS portfolios (CT = combustion turbine, CC = combined cycle, CHP = combined heat and power)

2.1.2 Western Interconnection Portfolio Overview

Most of the scenarios analyzed for this study use the Western Electricity Coordinating Council (WECC) 2024 Common Case portfolio (WECC 2014) as the base portfolio for resources outside of California (with the exception of renewable generation added out-of-state as part of the California renewable portfolio). California currently imports a significant amount of power, and these imports may go down in the future as prices fall during mid-day hours when renewable generation is high. Neighboring states may have incentives to purchase energy during these low-price hours, although higher renewable penetrations in the neighboring states could reduce the incentive to purchase power during these times. To investigate this issue, we created the High West portfolio, which assumes a higher renewable energy and energy efficiency buildout in the rest of the Western Interconnection. The High West portfolio is paired with the Baseline or Target California portfolios to create a complete portfolio in the High West scenarios. The increased renewable energy penetration reflects a situation in which the other western states (or the U.S. government) adopt increasing low-carbon policies, or RPS requirements. This case addresses a situation in which California's neighbors have less ability to accept surplus renewable generation from California when renewable resource generation cannot be completely absorbed in state. While the original penetrations from the Transmission Expansion Planning Policy Committee (TEPPC) 2024 dataset contains 16% renewable penetration outside California, the High West portfolio represents 35% penetration. Table 2 shows the penetration of out-of-state generation for each region in the original portfolios and the High West portfolio. More detail on the High West portfolio is available in the Appendix.

Table 2. Out-of-State Renewable Generation

Region	RE Penetration in original portfolios (%)	RE Penetration in High West portfolio (%)	PV Penetration in High West portfolio (%)	Wind Penetration in High West portfolio (%)	Other Penetration in High West portfolio (%)
Pacific Northwest	17	21	6.4	10.3	3.9
Idaho	17	21	5.9	11.7	3.1
Colorado / Wyoming	16	58	12.8	44.4	0.8
Montana	18	103	6.0	97.3	0.0
Nevada	31	39	7.7	11.5	19.7
New Mexico	14	53	18.7	29.7	4.6
Arizona	15	32	19.1	4.3	8.5
Utah	6	24	15.0	5.8	2.7
Total	**16**	**35**	**11.4**	**18.7**	**5.2**

2.1.3 Baseline Generation

California's renewables capacity in the Baseline portfolio is based on the CPUC's 2014 LTPP Trajectory scenario, which represents California Energy Commission (CEC) and CPUC assumptions about what California's 2024 generation portfolio would look like with no changes to current trends and conditions. To construct the LCGS Baseline portfolio, sufficient fixed-tilt solar PV was added to the CPUC's Trajectory scenario to maintain compliance with the 33% RPS based on projected load and energy efficiency growth between 2024 and 2030. Additionally, per language in recent Los Angeles Department of Water and Power (LADWP) Integrated Resource Plan (IRP) (LADWP 2014), a new combined-cycle plant was added to replace the coal-fired Intermountain Power Project in Utah.

2.1.4 Target Generation

The Target portfolio is also based off of the 2014 LTPP Trajectory scenario, but includes a larger amount of additional clean-energy resources than the Baseline portfolio. The additional renewables in the Target portfolio, added to enable reductions in electric-sector emissions, include a mix of solar PV, concentrating solar power (CSP), wind, geothermal, and biopower resources developed through an expert elicitation process, which included industry members from the Steering Committee of the LCGS study. Based on recommendations from this process, portfolios for each resource were constructed in the following way:

- Additional utility-scale PV is weighted heavily toward single-axis tracking (80% of utility-scale solar PV added to the 2014 LTPP portfolio in the Target portfolio was assumed to be single-axis tracking). Additional CSP is assumed to use power tower technology and 6 hours of thermal energy storage (TES).

- Wind resources are a mix of additional development in Tehachapi and repowering of 30-year-old technology in the Altamont, Tehachapi, and San Gorgonio areas of California and high-capacity-factor wind projects in Wyoming and New Mexico. The out-of-state wind is placed so as to minimize the need for new transmission to support those projects.

Additional transmission necessary to supply this generation to California load, and this is discussed in section 2.1.6. These two additional lines connect Wyoming wind to Delta (Utah) and New Mexico wind to Four Corners. The wind resource information came from AWS TruePower work for the Western Renewable Energy Zones project (WGA 2012)

- Flash geothermal in the Salton Sea area is included in accordance with the Salton Sea Restoration and Renewable Energy Initiative (Imperial Irrigation District 2015) and other resource assessments.

- Biomass and biogas production primarily consists of CEC accounts of existing biopower facilities (CEC 2015) and requirements for new procurement from State Bill 1122.

- The level of customer-sited rooftop PV is the same in all portfolios (Baseline, Target, and Target High Solar). The construction of the Target portfolio was based on assuming more aggressive emissions reduction and clean-energy policies at the utility scale. Because there is no explicit assumption about extension of incentives for rooftop PV in California, there was no reason to differentiate the levels of rooftop PV between portfolios. In this study, rooftop PV counts toward the renewable penetration percentages (as a fraction of gross load) shown in tables and figures. This may differ from past, current, and future RPS rules.

- Changes to energy efficiency, storage, and transmission in the different portfolios are noted below in section 2.1.6.

2.1.5 Target High Solar Generation

The High Solar portfolio is a variation on the Target portfolio in which the added utility-scale renewables are more heavily weighted toward solar PV than in the Target portfolio. This represents a continuation of current procurement trends and prioritization of in-state resources. It also represents a portfolio with lower upfront capital costs compared to the Target portfolio (Marcus 2015). The High Solar portfolio contains the same amount of annual available renewable energy and energy efficiency as the Target portfolio, but the additional renewables portfolio added beyond the Baseline contains no additional biomass, only one out-of-state wind project (Wyoming), similar amounts of California wind to the Target portfolio, and a smaller amount of California CSP and geothermal. Utility-scale solar PV comprises the rest of the renewables portfolio. Compared to the Target portfolio, the Target High Solar portfolio replaces 23 TWh of geothermal, out-of-state wind, biomass, and CSP-TES with in-state utility-scale PV generation.

2.1.6 Energy Efficiency, Storage, and Transmission

The CEC's *California Energy Demand Forecast, 2014–2024* (Kavalec et al. 2014) was used as the basis for load projections in all cases. The "Mid" additional energy efficiency case was used as the basis for the load in the Baseline portfolio. We assumed that the low-carbon policies would motivate more energy efficiency in the Target portfolios, so these portfolios (Target and Target High Solar) assume the "High-Mid" additional energy efficiency from the CEC. Both efficiency estimates were extrapolated from 2024 to 2030. The "High-Mid" efficiency estimate amounts to 20 TWh less load than the "Mid" scenario, and it is consistent with the California policy direction of doubling of the energy efficiency goals for the state. However, when examining in detail the supply curves underlying this assumption, it is apparent that this level of energy efficiency cannot be achieved by a business-as-usual energy efficiency program. The Energy Efficiency Industries Council put together a proposed program to achieve these savings that depends first on mandating these savings in new construction, then incentivizing retrofits in existing buildings with a significant contribution of public money for rebates and financing plus a retrofit-upon-resale ordinance. This is the "High-Mid" scenario that was used for the Target and Target High Solar portfolios. For capital cost analysis, see the companion LCGS report (Marcus 2015); for details on the energy efficiency assumptions, see the report by Tierra Resource Consultants (2015).

Demand response in all the cases is based on the "projected availability" from Olsen et al. (2013), except in the demand response and storage sensitivity described in section 2.2, which uses the "theoretical availability." The projected availability case assumes that about 2.5% of load is responsive, although about 80% of that comes from managed charging of electric vehicles. Although no vehicle-to-grid flows are assumed, the electric vehicles can potentially reduce curtailment by up to 2,800 MW during mid-day hours. Details of the demand response and electric vehicle assumptions are in the Appendix.

In addition to renewable resources, the Target portfolio also includes more bulk storage and transmission than the Baseline portfolio. The additional bulk storage in the Target case is one pumped hydro storage facility in California (1 GW) and one compressed-air energy storage (CAES) facility (1.2 GW) in Utah to support the Wyoming wind project. These storage facilities are in most of the Target scenarios. See section 2.2 for a discussion of sensitivities that do not include the additional storage in the Target portfolio.

The additional transmission is primarily associated with out-of-state resources. One line connects the Wyoming wind project to the terminus of the Intermountain Power Project DC line in Delta, Utah; this is a simple radial line. Another line connects the New Mexico wind project with the Four Corners region. This region has coal resources that will be retiring or no longer providing specified power to California, so this allows room for new wind imports. There is also a line in the Target cases connecting southern Idaho to southern Nevada. This line improves power-transfer capability between the northern and southern portions of the Western Interconnection. It reduces flows on California's otherwise heavily loaded Path 26. Improved power-transfer capability between the northern and southern portions of the WECC grid is important for cases with significant solar resources in California and Arizona—generation from resources in these areas needs to be moved northward where there is an economic use for the energy. Deliverability of renewable energy from Imperial Irrigation District (IID) is assumed to be possible due to approved transmission projects that will provide up to 1,800 MW of incremental transmission deliverability (CAISO 2015), and also due to changing flow patterns with reduced imports of gas-fired electricity into California.

2.2 Sensitivities

The institutional framework and technologies that exist for the future grid have significant impacts on the efficiency with which a low-carbon grid can be implemented. As part of the LCGS, we aimed to analyze and understand the key drivers for the metrics of interest (e.g., production cost, curtailment, emissions, imports, and gas fleet utilization). To do that, we identified a list of parameters that were likely to be key drivers of these metrics. We studied the effect of varying these parameters in a number of sensitivities, which are described at the end of this section. The following is a bulleted list of the parameters and constraints we chose to vary:

- **How out-of-state renewable energy is delivered.** Current California RPS regulations specify how much RPS-eligible energy from out-of-state resources must physically be delivered into the state. Specifically, by 2020, at least 90% of RPS energy must either be directly interconnected in state or delivered to California. Following the current modeling practices of CAISO, we constrain 70% of out-of-state RPS energy to be delivered in every hour to California under the conventional flexibility assumption suite.[5] We test the effects of loosening this constraint and therefore allowing out-of-state RPS energy to stay out-of-state during periods where there is a surplus of low variable-cost energy available in California. This assumption is intended as a proxy to represent potential institutional constraints that would require imports; it is not intended to represent the RPS Portfolio Content Categories or "buckets" directly. This constraint naturally eliminates net exports and requires imports during every hour (which vary based on generation levels at the out-of-state generators).

- **How operation of the conventional gas fleet is treated.** California ISO is considering whether a minimum regional generation requirement is needed to maintain compliance with applicable reliability standards; e.g., maintaining the CAISO's responsibility as balancing authority for a proportional share of the Western Interconnection's frequency response obligation. Initially, based on discussions with neighboring authorities, the CAISO recommended that a minimum of 25% of the energy to serve load must, at all times, be supplied by specified synchronous generation located in specific load pockets within the CAISO Balancing Authority and by specified synchronous generation in several other balancing authorities inside California. Generally, only dispatchable hydroelectric units and conventional gas-fired generators can contribute to the requirement because they have inertia and automatic generation control (AGC) response capability. This minimum generation requirement is a constraint modeled in the simulations during commitment and dispatch. CAISO and WECC have implemented similar constraints as part of their respective modeling processes, although these constraints will be revised soon by both organizations.

  In practice, this "25% rule" serves to address several concerns that arise with increasing renewable penetration. These concerns arise from a reduction in the number of online thermal units under a higher renewables penetration, and therefore a reduction of the services that these units provide.

[5] Because energy from both renewable and non-renewable resources commingle on the grid and flow to load in accordance with the laws of physics, the renewable delivery constraints embedded in law are given effect through accounting logic. For example, assuming there were 10,000 MW of out-of-state renewable generation in an hour that is specified for California, the simulation imposes operational constraints on aggregate in-state generation such that there would be at least 7,000 MW of net imports of energy into California for that hour. If this constraint cannot be satisfied by minimizing the output of in-state dispatchable generation, curtailment of renewable generation would be required. Whether all 7,000 MW of net imports are actually from out-of-state renewable energy sources is unknown because the least-cost system-wide dispatch does not match specific resources with specific loads.

These services include voltage support, frequency response, upward and downward reserve provision, and generation located physically near load centers. In addition, reducing the amount of generation from rotating machines with inertia and increasing inverter-based generation (e.g., PV, wind, battery storage, or high-voltage direct current [HVDC]) below a certain point may cause violation of North American Electric Reliability Corporation (NERC)/WECC reliability standards (Liu 2014). However, many of these services can be provided from other technologies. For example, batteries and wind resources can provide upward or downward reserve and synthetic inertia, and inertia can also be provided from synchronous condensers (Miller 2015). This constraint (as proposed by the CAISO) is enforced under our conventional flexibility assumptions.[6] In the enhanced flexibility cases, other non-combustion means are employed to meet these reliability constraints. These reliability concerns are discussed in more detail in section 4.2.4, and they were the subject of a LCGS report by GE Energy Consulting.

- **Increased deployment of demand response and energy storage.** Generation from weather-dependent resources such as wind and PV may have a limited coincidence with periods of high energy prices.[7] Technologies such as energy storage and demand response can address the mismatch between wind and solar output, and time periods with highest prices. Our conventional flexibility assumptions see energy-storage deployment limited to the CPUC-mandated targets and a relatively small amount of demand response. We test the assumption by increasing pumped hydro storage penetration by 2 GW and using "theoretically available" demand-response implementation (Olsen et al. 2013) in one scenario.

- **Diversity of renewable resource procurement.** Increasing the technological and geographic diversity of renewable resources can help reduce the variability associated with renewable generation (E3 2014; Lew et al. 2013; Bloom et al. 2015). The development of the Target case portfolio emphasizes resource diversity over upfront capital costs. We assess an alternate renewable buildout that increases low-capital-cost, in-state resources. This case is referred to as the "High Solar" portfolio, and it reflects current procurement trends for PV in California. Out-of-state wind and higher capital cost sources such as CSP, geothermal, and biomass are swapped out for in-state PV in the "High Solar" portfolio.

- **Deployment of renewable energy in neighboring states.** Historically, the CAISO has been a net importer of energy in every hour (Liu 2014). The bulk of these imports have been fossil-based. As California increases its share of renewable energy, these net

[6] As yet, there are no studies available demonstrating that the CAISO Balancing Authority's NERC-required frequency response obligation must be supplied by generators located within specific CAISO load pockets. If this constraint were removed, it may be possible to meet the CAISO Balancing Authority's frequency-response obligation at a lower cost and with units that have lower minimum output levels (which would reduce the possibility of renewable resource curtailment). (See City of Redondo Beach testimony in 2014 LTPP, Firooz 2015.)
[7] With increasing amounts of solar resources, time periods with high energy demands may not always coincide with the highest energy prices. The de-synchronization of energy demand and energy prices may be most observable during the midday hours of April, May, and June, when an abundance of solar energy depresses market clearing prices. The changing pattern of energy prices will likely require changes in the basic structure of demand-response programs.

imports are often displaced, and at times California may even wish to export energy during times of high renewable generation. During these times, the energy prices in California may be close to zero or even negative, meaning that neighboring states would have extra incentives to purchase low-cost energy from California. However, if other states in the western United States adopt aggressive low-carbon policies or RPSs, the neighboring states may be less willing (or even unable) to absorb extra generation from California. We assess this situation by increasing renewable penetration throughout the western United States in the "High West" set of scenarios.

- **The real-time interaction between California and neighboring regions.** Current transmission schedules in the CAISO market are largely determined in the day-ahead market. In fact, even if real-time CAISO prices are negative, the import and export schedules determined in the day-ahead market remain mostly unchanged (Liu 2014). The inflexibility of real-time energy scheduling is examined in a sensitivity that locks the day-ahead import schedules through to the real-time simulation.

- **Hydrologic conditions.** Recent droughts in California and the western United States have caused concern that these conditions might become more common. Wetter conditions could also make integrating renewable generation more challenging at certain times and places. We examine the impacts of wet and dry hydrologic conditions throughout the west by multiplying the capacity and monthly energy generation from the WECC TEPPC 2024 dataset by multipliers derived from the ratio of the hydro generation in the WECC TEPPC dataset to wet (2011) and dry (2001) hydro years. This is described in more detail in the Appendix.

- **Natural gas and carbon costs.** The most economic operation of the power system is dependent on operating costs. Fuel comprises the largest portion of operating costs, followed by emissions (in this case, carbon) costs. Thus, relative changes in fuel and carbon costs can greatly impact power system operation. Typically, coal power plants operate as "baseload" power plants, maximizing their output because they operate on the cheapest fuel. Natural gas power plants generally are more efficient and agile than coal power plants, and they produce fewer carbon emissions per unit of energy generated. However, they use a more expensive fuel and are often more expensive to operate than coal plants. Low-cost gas and high-cost carbon may render gas generation cheaper than coal generation, resulting in gas-fired plants operating with a higher capacity factor because they would be dispatched before coal. We examine the cost, emissions, and curtailment impacts of a combination of lower gas prices and higher emissions costs.

To efficiently study the interaction between these flexibility options and various generation portfolios, we created two suites of assumptions about the "flexibility framework" of grid operations, which we applied atop the Baseline, Target, or High Solar portfolio when running the model. We refer to these two suites of assumptions as the "conventional" or "enhanced" flexibility frameworks, and the assumptions that differentiate the two are described in Table 3. The conventional flexibility framework is intended to represent a system that is somewhat more flexible than today's grid, while the enhanced flexibility framework represents a system that is substantially more flexible than today's grid. Section 3 (Table 5) discusses some of the changes between grid flexibility today and the assumptions included in the conventional flexibility framework.

Table 3. Grid Flexibility Suite of Assumptions

Assumption	Conventional Flexibility	Enhanced Flexibility
Import requirements	70% of out-of-state (CA-entitled) renewable, nuclear, and hydro generation must be imported	Only physical limitation on imports and exports
Minimum local generation requirements	25% of generation in California balancing authorities must come from local fossil-fueled and hydro sources	No minimum local generation requirements
Storage buildout	1.5 GW battery storage to meet PUC requirement (CPUC 2013)	1.5 GW battery storage to meet PUC requirement, 1 GW pumped hydro, and 1.2 GW out-of-state CAES
Ancillary service limitations	In addition to physical limitations on ancillary service provision, capacity of hydro and pumped storage that can provide ancillary services are limited	The capacity of hydro and pumped storage that can provide ancillary services is doubled from the conventional assumptions

In addition to the California portfolio changes noted in section 2.1 (Baseline, Target, and High Solar), we also tested sensitivities around import rules, gas generation, hydro availability, natural gas and carbon prices, and other metrics. Using the basic structure of combining a generation portfolio with a flexibility framework to create a model of the Western grid, we ran 23 annual simulations of the model to understand the impact of some of these parameters on emissions, production cost, curtailment, and other metrics of interest. Table 4 shows the full matrix of scenarios and assumptions for all of the modeling runs performed for the LCGS. The scenarios are presented with more detailed information on the assumptions in section 4 (Table 6).

Table 4. Matrix of Sensitivities for LCGS Modeling

California Portfolio	Non-California Portfolio	Flexibility Framework (see Table 3 for detailed description)	Revised Assumptions	Shorthand
Baseline	Existing RPS	Enhanced	-	Baseline Enhanced *
Baseline	Existing RPS	Enhanced	Low gas / high CO_2 price	Baseline Enhanced, Low Gas + High CO_2
Baseline	Existing RPS	Conventional	-	Baseline Conventional*
Target	Existing RPS	Enhanced	-	Target Enhanced*
Target	Existing RPS	Enhanced	With 70% import requirement	Target Enhanced, With Import Rule
Target	Existing RPS	Enhanced	With 25% local gen requirement	Target Enhanced, With 25% Gen Rule
Target	Existing RPS	Enhanced	Low gas / high CO_2 price	Target Enhanced, Low Gas + High CO_2

California Portfolio	Non-California Portfolio	Flexibility Framework (see Table 3 for detailed description)	Revised Assumptions	Shorthand
Target	Existing RPS	Enhanced	High hydro	Target Enhanced, Wet Hydro
Target	Existing RPS	Enhanced	Low hydro	Target Enhanced, Dry Hydro
Target	Existing RPS	Conventional	-	Target Conventional*
Target	Existing RPS	Conventional	Locked day-ahead (DA) import schedules	Target Conventional, With Locked DA Imports
Target	Existing RPS	Conventional	No 70% import requirement	Target Conventional, No Import Rule
Target	Existing RPS	Conventional	No 25% local gen requirement	Target Conventional, No 25% Gen Rule
Target	Existing RPS	Conventional	Additional storage/DR	Target Conventional, With High Storage + DR
Target	Existing RPS	Conventional	High hydro	Target Conventional, Wet Hydro
Target	Existing RPS	Conventional	Low hydro	Target Conventional, Dry Hydro
Target High Solar	Existing RPS	Enhanced	-	Target Enhanced, High Solar
Target High Solar	Existing RPS	Conventional	-	Target Conventional, High Solar
Baseline	High West penetration	Enhanced	-	Baseline Enhanced, High West
Baseline	High West penetration	Enhanced	Low gas / high CO_2 price	Baseline Enhanced, High West, Low Gas + High CO_2
Target	High West penetration	Enhanced	-	Target Enhanced, High West
Target	High West penetration	Enhanced	Low gas / high CO_2 price	Target Enhanced, High West, Low Gas + High CO_2
Target	High West penetration	Conventional	-	Target Conventional, High West

* denotes core cases

3 Methods and Assumptions

This section describes the methods and assumptions used for the simulations for LCGS. Most of the differences between scenarios have been described in section 2 (both portfolios and assumptions regarding conditions on the grid), and the methods here apply to all scenarios unless specifically noted. The most important assumptions and the significant changes to existing models will be included here; the Appendix includes more detail.

One of the primary goals of this work was to model the operation of the power system to understand the economic and emissions impacts of the low-carbon portfolios under a range of assumptions. To do this, we used the PLEXOS Integrated Energy Model to perform hourly unit commitment and economic dispatch modeling for the Western Interconnection. Because California exchanges significant amounts of power with the rest of the western United States, it is important to model the entire Western Interconnection. This includes the ability to optimize between regions while including hurdle rates (from WECC TEPPC 2024 Common Case assumptions) to reflect friction between balancing authorities.

The model simulated a day-ahead, intra-day, and real-time operations (see Figure 3). The day-ahead simulation included day-ahead forecast error on renewable generation and this simulation committed the long-start generators (e.g., out-of-state coal generation) and fixed the hydro and storage dispatch. The intra-day simulation included 4-hour-ahead forecast error on renewable generation and fixed the commitment of natural gas combined-cycle units. Results presented in this work are from the real-time simulations, after considering error in forecasts for wind and solar generators. The real-time simulations were performed with hourly time resolution for all scenarios presented in the main report.

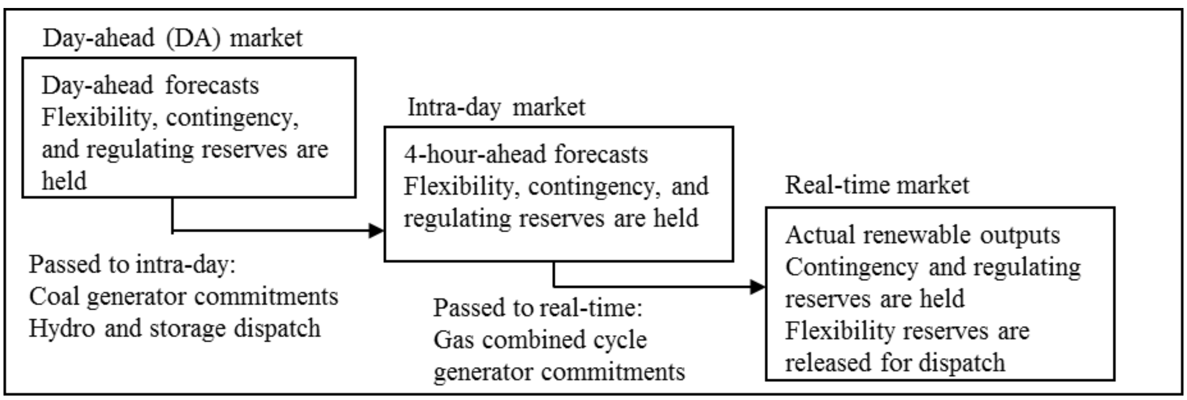


Figure 3. Day-ahead, intra-day, and real-time markets

We ran three of the scenarios (Baseline Enhanced, Target Enhanced, and Target Conventional, High Solar) with 5-minute resolution to analyze the impact of sub-hourly resolution on the key results of the study. These results are in the Appendix, and most of the key metrics (e.g., differences in costs between scenarios, curtailment) changed modestly in the sub-hourly simulations. The 5-minute runs showed larger production cost savings ($18–$144 million per year) from the renewable energy and energy efficiency because the more expensive combustion-turbine generators were used more often in the Baseline 5-minute runs, and they were displaced more by the renewable generators. Because the sub-hourly solutions took several days to solve the real-time market and produced large amounts of data, we ran most of our simulations with hourly time resolution so that we could run more scenarios, and the hourly results are presented in this report.

The following lists the key assumptions (and some background) that are included in all scenarios, unless otherwise noted:

- The base dataset for the analysis is the WECC TEPPC 2024 Common Case. This dataset is heavily stakeholder-vetted and commonly used to address questions such as the ones being addressed in LCGS.

- The 2024 Common Case was adjusted for generators in California. These generators were compared to the CAISO 2014 LTPP PLEXOS dataset. In cases where generators could be matched between the cases, key parameters such as maximum capacity, minimum stable level, and ramp rates from the CAISO database were included in the LCGS dataset. Many of these parameters are generic (not unit-specific) in the 2024 Common Case, but the CAISO database is mostly unit-specific.

- Transmission congestion was modeled at nodal resolution in California (honoring all WECC path ratings) and at a zonal resolution outside California. This allows for detailed congestion representation in California while keeping run-time reasonable. Although full nodal power flow was simulated, individual line constraints were not enforced; only the 67 WECC paths[8] are enforced in the modeling.

- The renewable generation hourly and 5-minute profiles were based on profiles developed for the Western Wind and Solar Integration Study and refined for phase 2 of that study (Lew et al. 2013). These profiles include modeled wind, solar PV, and solar CSP forecasts for the day-ahead and 4-hour-ahead simulations and actual generation profiles. Locations were selected based on the portfolios and the location of the generation buildout.

- Diablo Canyon Power Plant's license is assumed to expire due to the potentially high cost associated with extending the license and availability of baseload zero-carbon resources that could be lower cost. Because Diablo Canyon is a zero-carbon source of energy, the assumption of retirement makes reaching a carbon target more challenging.

- The Intermountain Power Plant 1,900 MW coal plant is retired prior to 2030 (currently scheduled to happen in 2025). In the Baseline portfolio, this was replaced with a 1,200 MW natural gas combined-cycle unit, a conversion that is planned in the 2014 LADWP IRP (LADWP 2014). In the Target portfolio, it is replaced with a CAES unit of similar size. In the Target Conventional scenarios, it is not replaced with anything because storage is limited in those scenarios.

- All cases comply with Assembly Bill 2514 and the CPUC storage mandate. We assumed that procurement will be slightly higher than the 2020 energy-storage procurement targets (about 1,300 MW) by 2030, resulting in 1,500 MW of storage by 2030 in all LCGS portfolios. Some of the scenarios add additional storage beyond this.

- 3,400 MW of gas generation is modeled as combined heat and power or qualifying facilities (CHP-QF). These facilities are must-run in the model, but have a minimal amount of flexibility to reduce their output to 55% of maximum capacity. This is consistent with current contracting practices, which encourage the development of

[8] The WECC paths are key transmission lines that are grouped for operational and planning purposes.

"operationally flexible resources" to help assist with renewables integration (CPUC 2010).

- The California burner-tip natural gas price averages $6.96/MMBtu. This is derived from the Energy Information Administration (EIA) mid-case projection of the Henry Hub price in 2030 and is comparable to the gas price used by the CPUC in its modeling and somewhat lower than the gas price used by LADWP in its IRP (but significantly higher than today's prices). This has regional and monthly multipliers based on the WECC 2024 Common Case. Coal price is from the 2024 Common Case and varies regionally, but averages about $2/MMBtu. Carbon price in California is $32.44 per metric ton based on the CEC "low" forecast and extrapolated to 2030 (Kennedy et al. 2014). These prices are extremely important for interpreting the production cost changes in the results. In the companion capital cost analysis, sensitivities are run on gas and carbon prices. In this study, we ran a gas and carbon price sensitivity to understand the consequences of a situation in which dispatching gas was cheaper than coal throughout the west.

- Carbon has no cost outside of California in the model. Specified imports, which are imports from specific California-owned sources (which by 2030 are only zero-carbon sources) such as Hoover Dam, Palo Verde Nuclear Generating Station, and out-of-state renewable generation, are charged no additional hurdle rate. Unspecified imports (imports above and beyond the specified imports) incur a hurdle rate equivalent to a carbon adder of the carbon cost ($32.44 per MT CO_2) times the assumed carbon intensity of imports (0.432 MT CO_2/MWh), which is about $14/MWh hurdle rate for unspecified imports.

- We assumed that 3 million electric vehicles (EVs) on the road would add 13 TWh of annual electricity demand (about 4% of California load). Half of these vehicles are assumed to be price-responsive or scheduled by the utility, whereas the other half charge when they are plugged in. See Appendix for details on EV assumptions.

- Demand response (DR) resources (in addition to price-responsive EV charging profiles) can shift about 0.5% of the total annual demand and reduce peak load by 905 MW. This is the "projected availability" from Olsen et al. (2013). The DR and storage sensitivity described in section 2.2 uses the "theoretical availability," which assumes that 5.2% of annual energy demand can shift and the peak load can be reduced by 6.4 GW. All of these assumptions are described in more detail in the Appendix.

- Reserves (contingency, regulation, and flexibility) must be provided within each reserve sharing group. In California, these include CAISO South (Southern California Edison [SCE] and San Diego Gas & Electric [SDG&E]), CAISO North (Pacific Gas & Electric [PG&E]), MUNI South (LADWP and IID), and MUNI North (Balancing Authority of Northern California [BANC] and Turlock Irrigation District [TIDC]). These groupings are slightly different than the larger bubbles that CAISO uses for their production cost models, but more reflective of reality.

- Reserve requirements for contingency reserves (for each reserve-sharing group mentioned above) were based on the WECC Common Case assumptions. For regulation and flexibility, the methods from phase 2 of the Western Wind and Solar Integration Study (Lew et al. 2013) were used, which consider uncertainty in load, wind, and solar forecasts and require online reserves to cover those uncertainties. These requirements are dependent on the portfolio. These methods yield reserve levels consistent with current CAISO regulation reserves modeling practice. Flexibility reserves are lower than CAISO load-following reserves in the 2014 LTPP PLEXOS model (see section 4.1.7 for details).

- Outside of California, one spinning-reserve product is modeled for each of the three regions in the western United States (the Northwest, the Rocky Mountain region, and the Desert Southwest). This spinning-reserve product represents regulation and contingency reserves. The simplification was made to reduce model run-time while minimizing impacts on dispatch of generators in California. Reserves associated with out-of-state variable renewable generation must be provided by in-state California resources.

- Ancillary services can be provided by any online thermal generators with spare capacity and ramp availability in all cases. Ancillary services can also be provided by a small subset of hydro generators as well as Castaic Pumped Storage Generator in all cases. The amount of hydro and pumped-storage capacity allowed to bid into the reserve markets was tuned so that the resulting fraction of hydro contribution to reserves was similar to recent history (see section 4.1.7). The limitations on which units can provide ancillary services was necessary because the physical capabilities of the hydro and pumped-storage units are sufficient to provide almost all ancillary services, which does not happen today. In the conventional grid flexibility assumptions, ancillary services can be provided by a larger subset of hydro and pumped-storage generators (doubling the capacity) consistent with physical capability to provide these services, as well as battery storage devices and CSP with TES.

The LCGS is intended to inform questions about the impacts of grid flexibility on the ability of the grid to integrate renewable energy and energy efficiency. Several of these grid flexibility options are captured in the enhanced and conventional flexibility frameworks, as described in Section 2.2. The conventional grid flexibility assumptions are intended to represent a less flexible grid compared to the enhanced flexibility scenarios, but there are still some differences between grid operation practices today and the conventional assumptions. Some of the key differences are noted in Table 5.

Table 5. Key Differences between Today and Conventional Flexibility Assumptions for LCGS

Difference	Impact
Model assumes central dispatch subject to constraints and hurdle rates	In reality, market friction (e.g., due to bilateral contracts or strategic offering) leads to out-of-merit order dispatch in some cases. Importing during times of curtailment and zero prices is one example. Although hurdle rates and other constraints lead to sub-optimal dispatch, dispatch in reality will differ from modeled dispatch. The model assumes that the optimal resources will have access to transmission if it is physically available.
Diablo Canyon nuclear generating station is assumed to retire in the LCGS scenarios	Although Diablo Canyon is a zero-carbon source of electricity and its operation would make reaching a carbon target easier, the retirement does allow greater flexibility in integrating renewables since the plant provides inflexible baseload energy.
1.5 GW battery storage to meet PUC requirement	This represents the 1.325 GW PUC storage mandate for 2020 (CPUC 2013), with some additional storage added for growth to 2030.
Combined heat and power assumptions	Assumed 3.4 GW of CHP-QF generators can be turned down to 55% of maximum capacity only during times of over-generation. Consistent with CPUC policy to encourage development of “operationally flexible resources” (CPUC 2010).
Electric vehicles assumptions	Assumes 3 million electric vehicles adding 13 TWh of load, with half of those vehicles available for optimal charging (either price-responsive or utility-controlled). The price-responsive EVs create a potential for up to 3,000 MW of load during times of curtailment.
Generation fleet and transmission infrastructure changes included in WECC 2024 Common Case and 2014 CPUC LTPP	Coal retirements and gas fleet changes as defined in the 2024 Common Case and CAISO LTPP 2014 PLEXOS model are included. Operational parameters in these datasets may not reflect historical operations for all generators. The Target case includes transmission upgrades needed to bring new California-entitled renewable power to transmission corridors (for Wyoming and New Mexico wind) and a north-south line from Idaho to southern Nevada for exchanging power between regions with different renewable resource mixes.
Deployment of rooftop PV	All cases include 24 TWh of rooftop or customer-sited PV. Rooftop PV reduces grid carbon emissions and operation costs. This benefit is present in all scenarios, and thus does not contribute to the relative differences in emissions and costs between scenarios.

4 Results

This section discusses the results of the operational analysis. Section 4.1 focuses on the core scenarios (Target Enhanced Flexibility, Target Conventional Flexibility, Baseline Enhanced Flexibility, and Baseline Conventional Flexibility). These scenarios inform the general impacts of the low-carbon grid compared to the Baseline scenario, and also study the overall impacts of assuming there are fewer changes to the way the grid is operated (in the conventional grid-flexibility assumptions) compared to assuming there are more changes to the way the grid is operated (in the enhanced flexibility assumptions). Section 4.2 discusses specific assumptions used across the full range of the sensitivities modeled in more detail to understand which assumptions have the most impact on certain outcomes. All results are presented in 2014 dollars. Table 6 shows some of the individual assumptions that vary between the different scenarios.

Table 6. Matrix of Assumptions for LCGS Modeling (* denotes core cases)

	Portfolio Assumptions					Operational Assumptions				Other Conditions		
	Baseline portfolio , 341 TWh load	Target portfolio, 321 TWh load	High Solar portfolio	Renewable energy penetration in non-CA West (%)	Additional GW storage (beyond 1.5 GW CPUC requirement)	70% out-of-state minimum import	Constrained reserves	25% min generation requirement	Locked day-ahead import schedule	Low gas / high carbon price	High hydro year	Low hydro year
*Baseline Enhanced	x			16	0							
*Baseline Conventional	x			16	0	x	x	x				
Baseline Enhanced, High West	x			35	0							
Baseline Enhanced, High West, Low Gas + High CO_2	x			35	0					x		
Baseline Enhanced, Low Gas + High CO_2	x			16	0					x		
*Target Enhanced		x		16	2.2							
*Target Conventional		x		16	0	x	x	x				
Target Enhanced, High Solar			x	16	2.2							
Target Conventional, High Solar			x	16	0	x	x	x				
Target Enhanced, With Import Rule		x		16	2.2	x						
Target Conventional, No Import Rule		x		16	0		x	x				
Target Enhanced, With 25% Gen Rule		x		16	2.2			x				
Target Conventional, No 25% Gen Rule		x		16	0	x	x					
Target Conventional, With High Storage + DR		x		16	2.0	x	x	x				
Target Conventional, With Locked Day-Ahead Imports		x		16	0	x	x	x	x			
Target Enhanced, High West		x		35	2.2							
Target Conventional, High West		x		35	0	x	x	x				
Target Enhanced, Dry Hydro		x		16	2.2							x
Target Enhanced, Wet Hydro		x		16	2.2						x	
Target Conventional, Dry Hydro		x		16	0	x	x	x				x
Target Conventional, Wet Hydro		x		16	0	x	x	x			x	
Target Enhanced, High West, Low Gas + High CO_2		x		35	2.2					x		
Target Enhanced, Low Gas + High CO_2		x		16	2.2					x		

4.1 Core Scenarios

The Target Enhanced Flexibility, Target Conventional Flexibility, Baseline Enhanced Flexibility, and Baseline Conventional Flexibility scenarios are examined in detail in this section. These four scenarios will be referred to as the “core scenarios.” The enhanced flexibility cases have a suite of assumptions that lead to increased grid flexibility compared to the conventional grid-flexibility assumptions, see section 2.2 for more detail. As described earlier, the conventional assumptions include a requirement that California import 70% of its out-of-state resources (including renewables and California's share of Hoover and Palo Verde) in every hour, a requirement that utilities in California must serve 25% of load by local thermal and hydropower resources (as implemented in WECC 2024 Common Case model), and further limitation on which hydropower resources can provide reserves. In the Target portfolio, the conventional flexibility assumptions also reduce the amount of storage added to the system. Although several of these assumptions are analyzed in more detail in section 4.2, the conventional and enhanced flexibility cases show the potential difference of a number of these assumptions in combination, providing bounding estimates for many of the outcomes of interest.

This section is organized by conclusions, with supporting figures, tables, and text below. Additional supporting information is available in the Appendix, as noted in specific locations in the text.

4.1.1 The production cost value of renewable energy and energy efficiency depends on the rest of the system and the institutional framework

The value of the energy efficiency (EE) and renewable energy (RE) resources depends on a number of different system conditions and assumptions. Table 7 shows the change in annual production costs, adjusted to isolate California from the Western Interconnection for the four core scenarios. There are other ways to isolate California-specific production costs, and we tested other methods that count production costs for all of the Western Interconnection and treated emissions due to changes in generation out of state differently. The production cost changes between scenarios are similar for all methods in the core scenarios.[9] Results for these methods are in the Appendix. Production costs are a portion of total utility costs; see Marcus (2015) for a discussion of the total costs for utilities in the different scenarios.

Table 7. Annual Production Cost for the Core Scenarios (millions of 2014$ per year)

Scenario	Costs from California Generators		Import Costs	Export Revenues	Total California Costs	Annual Savings
	Operational	Emissions	Purchased energy from out of state	Energy sold out of state	California generation + import costs – export revenue	Compared to Baseline Enhanced
Baseline Enhanced	8,606	1,988	2,161	-42	12,713	-
Baseline Conventional	8,739	2,025	2,060	-46	12,779	-65
Target Enhanced	5,830	1,279	1,000	-244	7,865	4,848
Target Conventional	6,458	1,436	754	-239	8,409	4,304

[9] The only scenarios that have significantly different cost differences depending on methodology used were the High West scenarios, which had major cost differences outside of California due to the renewable energy penetration.

- Operational costs include fuel, variable operation and maintenance, and startup costs.
- Import costs are calculated as the quantity of imports multiplied by the marginal price in the importing region of California.
- Export revenues are calculated as the quantity of exports (or out-of-state renewable generation that is part of the California portfolio) that is sold outside California multiplied by the marginal price in the receiving region. Negative values indicate revenues to California.

In the enhanced flexibility cases, the annual production cost value of the low-carbon (EE and RE) resources was about $4.8 billion per year. The value of the low-carbon resources is significantly lower in the conventional flexibility assumption scenarios ($4.4 billion per year). The enhanced flexibility helps the system realize more cost reductions from the RE and EE added in the Target portfolio. In the Baseline scenarios, the enhanced flexibility framework reduces production cost by $65 million per year; however, in the Target scenarios, the enhanced flexibility parameters lead to $550 million lower production cost compared to the conventional assumptions. This does not consider costs that might be required to implement the enhanced grid flexibility.

In addition to the enhanced vs conventional flexibility, other assumptions can have a significant impact on production cost. The Appendix contains a table with a comparison of production costs among all the scenarios. For understanding the tradeoffs between higher capital costs and lower production costs, see the full rate-impact analysis (Marcus et al. 2015).

4.1.2 Curtailment in a low- carbon grid could be less than 1% or over 4% with a diverse portfolio, depending on the flexibility of the grid and the study assumptions

Curtailment can vary significantly in the Target scenarios from as little as 0.2% in the Target Enhanced Flexibility scenario to 4.2% in the Target Conventional assumptions. Table 8 shows the curtailment (as a fraction of available generation from wind, solar, and geothermal) for the core scenarios and other indicators of system stress. The flexibility assumptions and the renewable penetration levels and portfolio are both key drivers of curtailment. The Baseline Conventional case has higher curtailment (as a percentage of available generation) compared to the Target Enhanced case (0.6% vs 0.2%), even though there is an additional 55 TWh of renewable generation and 20 TWh of energy efficiency in the Target Enhanced case. In the conventional flexibility assumptions, rules that require the gas fleet to be online lead to lower fleet-wide minimum generation levels, but individual units operate more frequently at minimum generation level. Exports (which are primarily out-of-state resources that are not imported into California) are significantly higher in the Target portfolio.

Table 8. Curtailment and Other Indicators of System "Stress"

Scenario	Curtailment (%)	Exports* (TWh)	Gas CC Percentage of Hours Operating at Minimum Generation Level (%)	Minimum Generation from California Gas Fleet (MW)
Baseline Enhanced	0.0	0.8	22	2,000
Baseline Conventional	0.6	0.8	31	5,500
Target Enhanced	0.2	5.2	8	1,800
Target Conventional	4.2	4.8	23	5,100

* Exports include physical exports and out-of-state renewable generation that was not imported. See section 4.1.3 for details.

Figure 4 shows the duration curve of hourly curtailment for the core scenarios. In the enhanced flexibility scenarios (and the Baseline Conventional), curtailment occurs primarily during a small number of hours. In the Target Conventional, curtailment occurs somewhere in the system more than one-quarter of the time and 4% of the annual possible generation is curtailed.

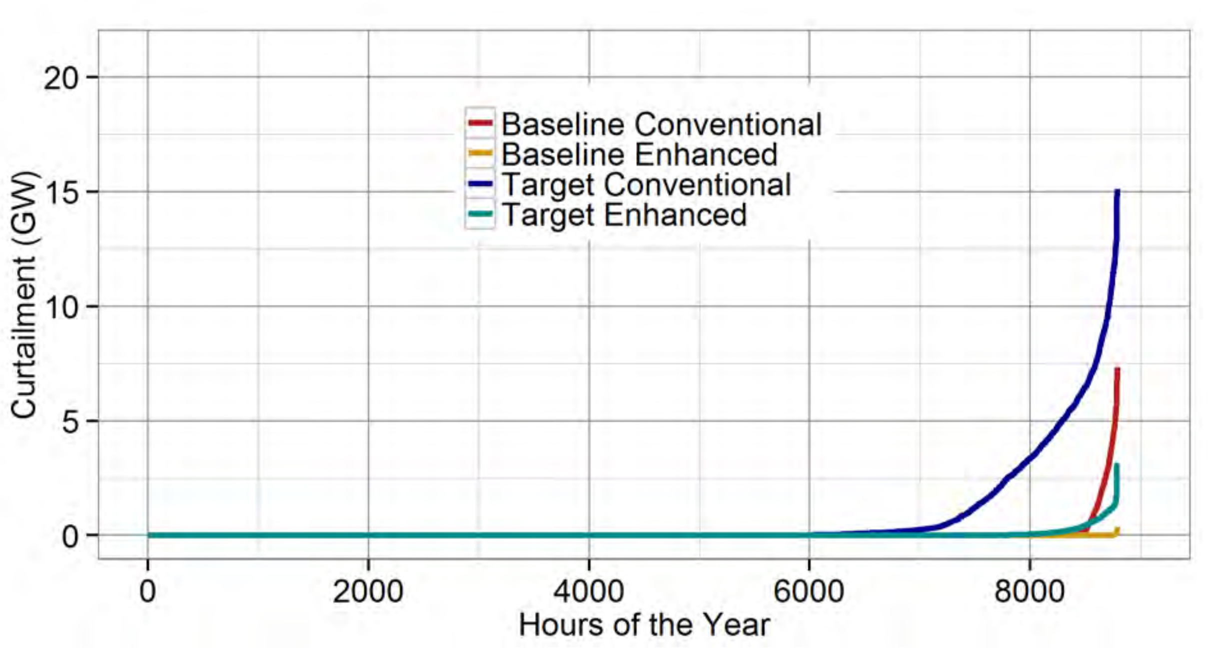


Figure 4. Curtailment duration curve for core scenarios

Many of the assumptions we tested in the sensitivities affect curtailment. Section 4.2 discusses many of the flexibility assumptions that impact curtailment, and section 4.2.2 discusses curtailment with the High Solar portfolio. Because of the high output of all solar PV generation at mid-day, high solar penetration scenarios could lead to higher curtailment than a more diverse portfolio. All of these scenarios consider central dispatch of the system in the model; in reality, bilateral contracts, strategic bidding and offering into the market, and other constraints that lead to out-of-market dispatch could increase curtailment above these modeled levels.

4.1.3 Physical imports into California are reduced compared to today and imports from fossil fuels in today's system are replaced with imports from renewable generation in the low- carbon grid

Figure 5 shows the physical import[10] duration curve for the core scenarios, in addition to an approximate import duration curve from 2013.[11] There is a significant reduction in physical imports between 2013 and the Baseline cases modeled in this study for 2030 (net imports were 96.8 TWh in 2013 vs 55.5 TWh in the Baseline Conventional). This is due to the retirement of coal generation in the west as reflected in the TEPPC 2024 Common Case and LADWP IRP, and the addition of in-state renewable resources. Physical imports are similar between the Baseline and Target scenarios for this study (Baseline is 55.5 TWh vs 56.1 TWh for the Target with conventional flexibility assumptions) because fossil-fueled imports are replaced with imports from the additional out-of-state renewable generation. Unspecified imports are reduced by 15–20 TWh between the Baseline and Target portfolios in the core cases (see Table 9).

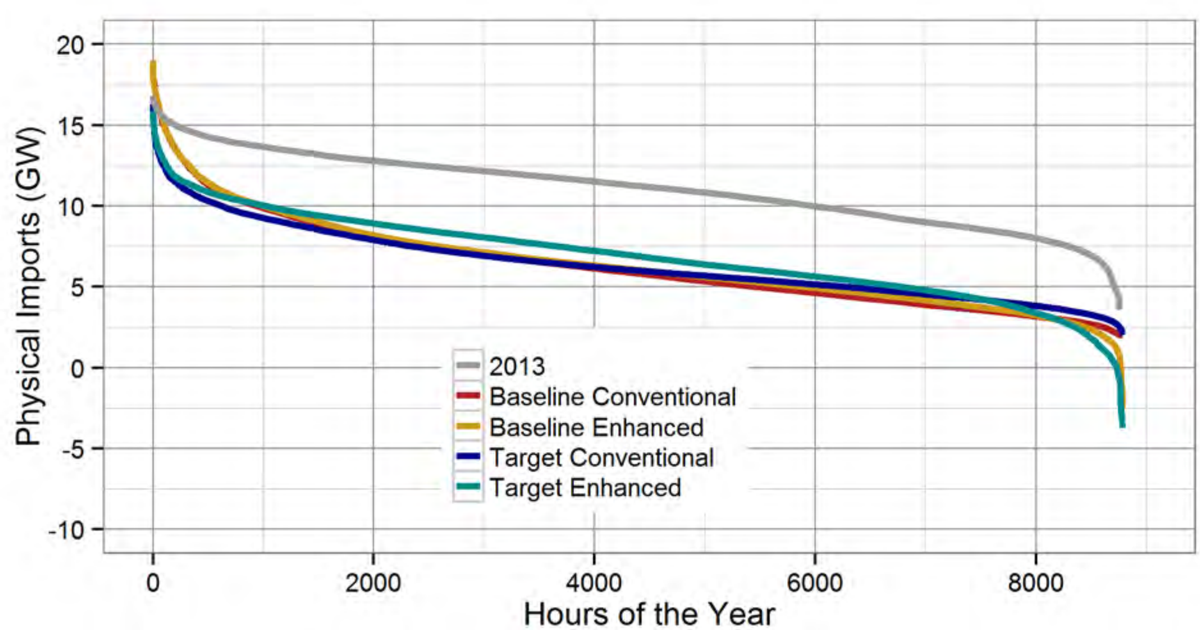


Figure 5. Import duration curve for core scenarios

Table 9 contains the annual import information for the core scenarios. As described in Section 3, specified imports are imports that are from California-owned (e.g., Palo Verde) or California-contracted (e.g., Hoover) out-of-state generators. These include renewable generation, and California's share of Hoover hydropower and nuclear generation from Palo Verde. Specified imports are either imported into California, or, if it is optimal, sold out of state. In the latter case, this energy is referred to as specified imports that are not imported. This phenomenon and physical exports (which occur during a small number of hours) are discussed in more detail in

[10] For this report, physical imports are defined as all imports that come into California on transmission lines, regardless of source. Physical exports are all exports that leave California on transmission lines, not including any California-entitled out-of-state generation that is sold out of state.

[11] Import duration curve is approximate, and based on scaling 2013 hourly CAISO imports to meet the total California annual imports from the 2013 California Energy Commission Almanac.

section 4.1.4. Unspecified imports are imports that come into California but are above and beyond the specified imports at any given hour. For carbon accounting, specified imports are zero-carbon (e.g., wind, solar, hydropower, and nuclear), whereas unspecified imports have typical carbon values associated with them (0.432 MT/MWh, see section 4.1.5 for details).

Table 9. Annual Import Information for the Core Scenarios (TWh)

Scenario	Annual Net Imports	Annual Net Exports	Specified Imports that are Imported	Specified Imports that are not Imported	Unspecified Imports
Baseline Enhanced	56.8	0.0	27.5	0.8	29.2
Baseline Conventional	55.5	0.0	27.5	0.8	28.1
Target Enhanced	60.5	0.1	46.0	5.1	14.5
Target Conventional	56.1	0.0	45.2	4.8	10.9

- Annual net imports are the total imports that occur during hours that California is a net importer, whereas net exports are exports that occur during hours that California is a net exporter.
- Specified imports are imports that come from California-entitled resources, including the out-of-state renewable generation and shares of Hoover and Palo Verde.
- Unspecified imports are imports that are above and beyond the specified imports.
- During each hour, if net imports are lower than the specified imports, the excess is classified as “specified imports that are not imported.” This power is sold outside of California in the model.

4.1.4 The optimal dispatch would likely have net physical exports during a small number of hours

As Table 9 shows, net exports (the total of exports during hours which California is a net exporter) are less than 0.5 TWh in all core cases, which is less than 0.1% of California load. We ran a number of scenarios where physical net exports were not allowed from California and 70% of out-of-state generation must be imported. Carbon targets based on the accounting methods (and counting all out-of-state California-entitled renewable generation) were still achievable. This is evidenced by the Target Conventional (45.0 MMT) and the Target Enhanced scenario with the 70% import requirement (41.8 MMT). This scenario is discussed in more detail in section 4.2.3. We did not include any scenarios where 100% of the out-of-state renewable generation is required to be imported or where the remaining 30% that stays out of state is given no emissions credit.

Although physical exports are negligible in the core cases, some California-entitled out-of-state generation is sold out of state in the core scenarios. This is labeled as “specified imports that are not imported” in Table 9.

Current California law requires that renewable generation satisfy one of three categories (Portfolio Content Categories or “buckets”) in order to qualify for the RPS. The first two categories require that delivery of renewable energy (or substitute electricity) must be made to a

California balancing authority. The third category does not require delivery and is commonly referred to as "unbundled renewable energy credits (RECs)." In the current bucket system, up to 10% of RPS energy can be unbundled RECs after 2017.

For this study, we are using "specified imports that are not imported" as a proxy for unbundled RECs. Specified imports that are not imported are California-entitled generation that is optimal to be sold out of state. This is not identical to the current unbundled REC system because this is a carbon-focused study, not an RPS study, and we do not attempt to designate a project as unbundled for the entire year. To calculate the specified imports that are not imported, we count all times when specified imports are larger than imports at a given hour; the gap between imports and specified imports are specified imports that are not imported. To meet the carbon target for this study, about 155 TWh of RE serving California load is necessary. The specified imports that are not imported stay below 10% of the RE in all core cases and almost all other cases. [12] Although this proxy variable is representative of today's RPS policy, current requirements that each RE project is assigned to a bucket (and cannot change between buckets hourly) means that not all of these scenarios would be compliant with existing RPS policy extrapolated to higher targets.

Figure 6 shows the unspecified import duration curve. All positive values on this chart are unspecified imports, or imports from generation that is not California-owned or California-entitled. Negative values are specified imports that are not imported, which is California-entitled generation that is sold out of state. The 70% import requirement reduces the amount of California-entitled generation that is sold out of state, especially during the hours of peak energy consumptions. For example, the Target Conventional scenario never sells more than 3 GW of California-entitled generation out of state compared to over 10 GW in the Target Enhanced scenario.

[12] The only scenarios that have more than 15 TWh of out-of-state California-entitled generation sold out of state are scenarios with low gas and high carbon prices throughout the west, because California generators are priced lower than many out-of-state generators (including coal) and there is little incentive for California to import in those scenarios.

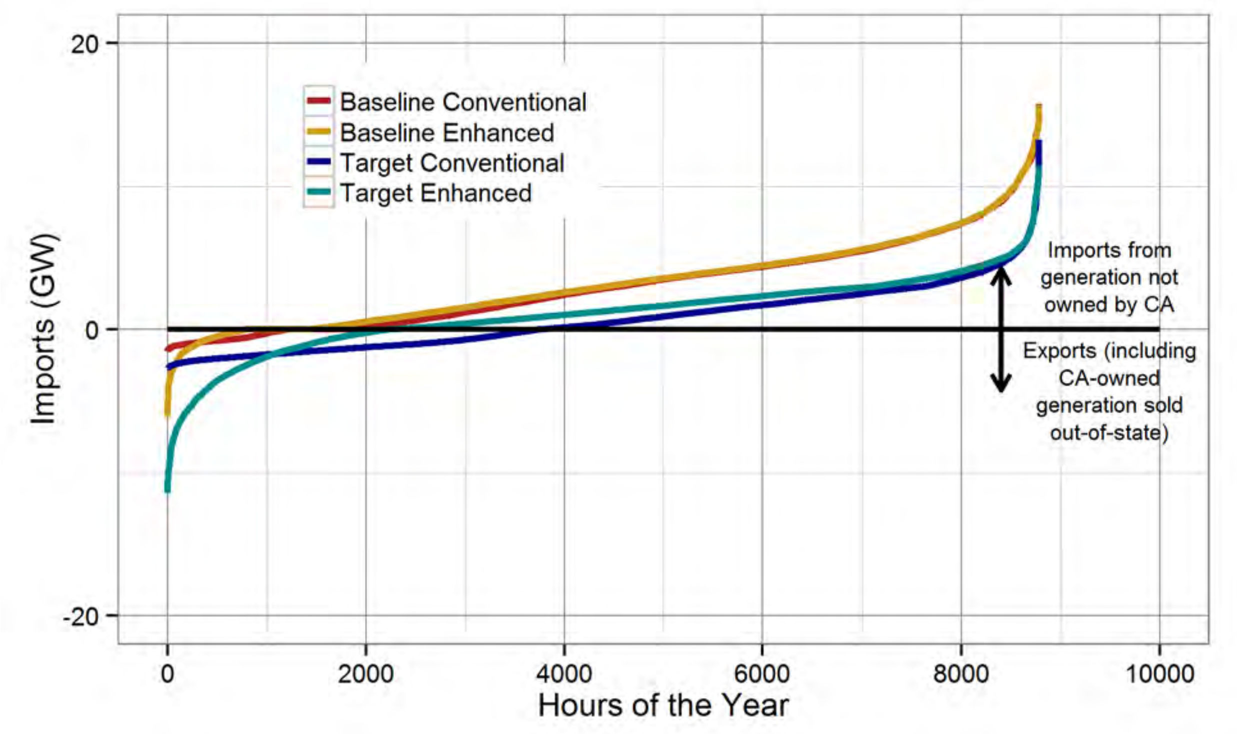


Figure 6. Unspecified import duration curve for core scenarios

4.1.5 California could achieve a 50% reduction in carbon emissions by 2030; emission reductions depend on calculation method and assumptions regarding institutional framework and portfolio

Table 10 shows the carbon accounting for the core scenarios. The CO_2 assigned to California load assumes a standard emissions rate (0.432 MT/MWh) for emissions and sales of California-owned generation out of state (the rate for the Pacific Northwest is 80% lower due to the abundance of zero-carbon hydro resources there). Although it is standard practice to de-rate the carbon emissions from power coming from the Northwest,[13] changing export levels to California likely has much more of an impact on the fossil-fueled generation levels in the Northwest than on hydroelectric output in the Northwest. The emissions impacts of any incremental adjustment to California imports from the Northwest is likely to have actual carbon emissions impacts closer to the standard gas assumption (0.432 MT/MWh) than the de-rated assumptions for the Northwest. However, to be consistent with previous work and carbon goals, we included the de-rate for the Northwest in the accounting method.

The results show that the institutional framework has a significant impact on carbon emissions. In the Target portfolio, the emissions reductions are almost 4 MMT less in the conventional flexibility case compared to the enhanced flexibility case. This difference is due primarily to the curtailment in the Target Conventional scenario, which causes less fossil-fueled generation to be displaced.

[13] http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/acs-power.htm.

Table 10. Annual Carbon Accounting, in Million Metric Tons (MMT)

Scenario	CO_2 from CA gas generators	CO_2 assigned to imports and exports	CO_2 assigned to CA load	Change in assigned California CO_2 emissions compared to Baseline	Total WECC CO_2 emissions	Change in WECC CO_2 emissions compared to Baseline
Baseline Enhanced	67.7	6.7	74.4	-	380.9	-
Baseline Conventional	68.9	6.3	75.2	0.8	381.0	0.2
Target Enhanced	43.7	-2.5	41.1	-33.2	345.1	-35.8
Target Conventional	48.9	-3.9	45.0	-29.4	349.3	-32.4

- Exports in this context include both net exports and specified imports that are not imported. This is zero-carbon energy that is sold out of state.
- Total WECC emissions not only include the western United States but also parts of Mexico and Canada (Alberta and British Columbia).
- Unspecified imports and exports are assumed to have a 0.432 MT/MWh carbon penalty (or credit). Unspecified imports from the Northwest have a penalty of 20% of 0.432 MT/MWh, which is consistent with the California Air Resources Board 2012 assumptions (CARB 2014) and the California ISO LTPP modeling (Liu 2014). CARB uses 0.022 MT/MWh for data year 2015.

Using this accounting method for assigning emissions, the Target portfolios reduce CO_2 assigned to California load by 29–33 MMT. However, the actual change in modeled emissions throughout the Western Interconnection was 32–36 MMT. This is because the method to assign emissions assumes that all displaced generation is natural gas, but some of the generation displaced in the scenarios is out-of-state coal (due to reduced unspecified imports and sales of California-entitled generation), which has emissions rates closer to 1 MT/MWh. Figure 7 shows the generation displaced by the Target portfolio in the enhanced and conventional assumptions. All generation to the right of the “0” on the x-axis is *increased* generation (e.g., wind, geothermal) compared to the Baseline Enhanced. All generation to the left of the “0” is *displaced* generation. About one-third of the displaced generation is located outside California. Most of the displaced generation is from gas CC units, whereas some of the out-of-state displaced generation is from coal-fired power plants.

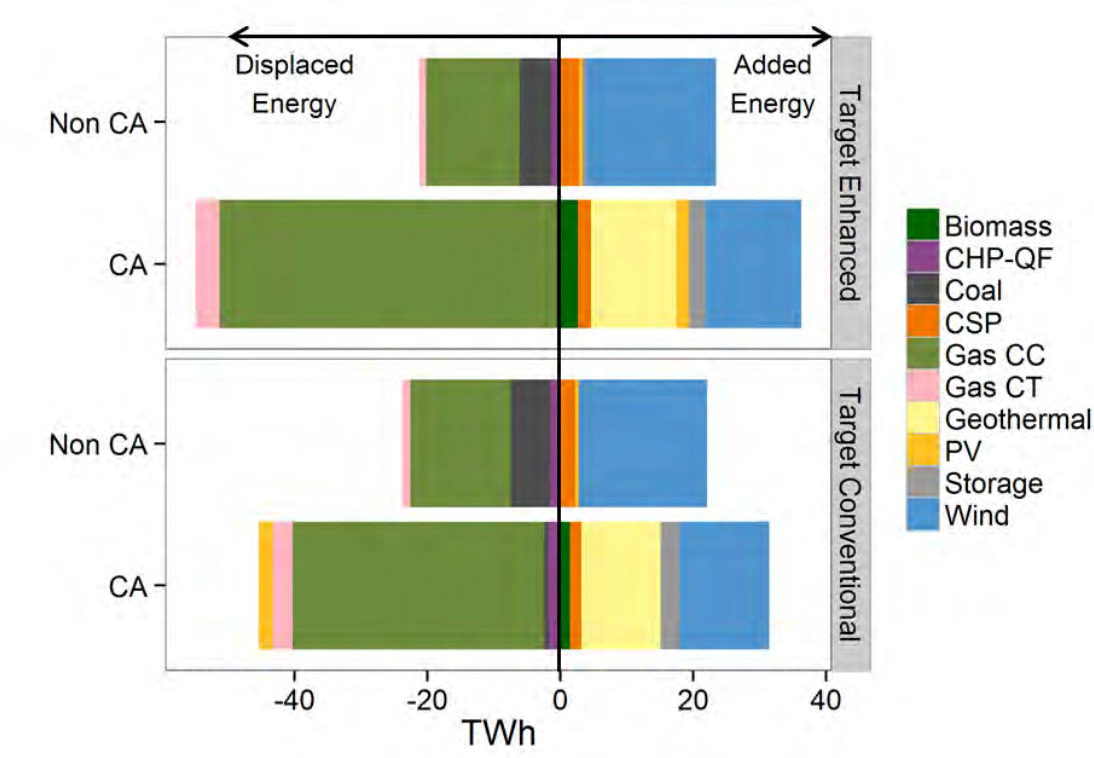


Figure 7. Displaced generation in the Target scenarios (compared to the Baseline Enhanced), classified by geographic location

The primary driver behind the difference in carbon emissions in the scenarios studied is curtailment, whether that curtailment is caused by a lack of diversity in the renewable portfolio, the 25% minimum regional generation rule, the 70% import constraint, or lack of storage. The cases that have higher curtailment displace less fossil-fueled generation and have higher emissions.

4.1.6 Utilization of the gas fleet depends as much on institutional framework as it does on renewable penetration

The usage of the gas fleet varies significantly between the scenarios. Figure 8 shows the duration curve of gas generation in California in the core scenarios. For most of the time, gas generation is significantly lower in the Target portfolio cases. The core Target portfolios have annual peak generation from gas-fired power plants (28–30 GW) that is lower compared to the Baseline portfolios (33 GW). During off-peak times, the institutional framework has larger impact than the portfolio. This is due primarily to the local generation rule that requires that at least 25% of generation from some of the California balancing authorities come from local thermal and hydro generation. This rule exists in the conventional cases, but not the enhanced flexibility cases. The conventional flexibility cases always have at least 5 GW of gas generation, whereas the enhanced flexibility cases have as low as 2 GW. In these cases, even the 3.4 GW of CHP-QFs turn down to provide flexibility. The CHP facilities are assumed to be allowed to turn down output to 55% of the maximum capacity, but the cost savings of turning down the output is very small and it will only happen when prices are near zero. Several hundred hours of turndown can be seen in the bottom right corner of Figure 8 in the Target scenario, where the slope of the curve changes.

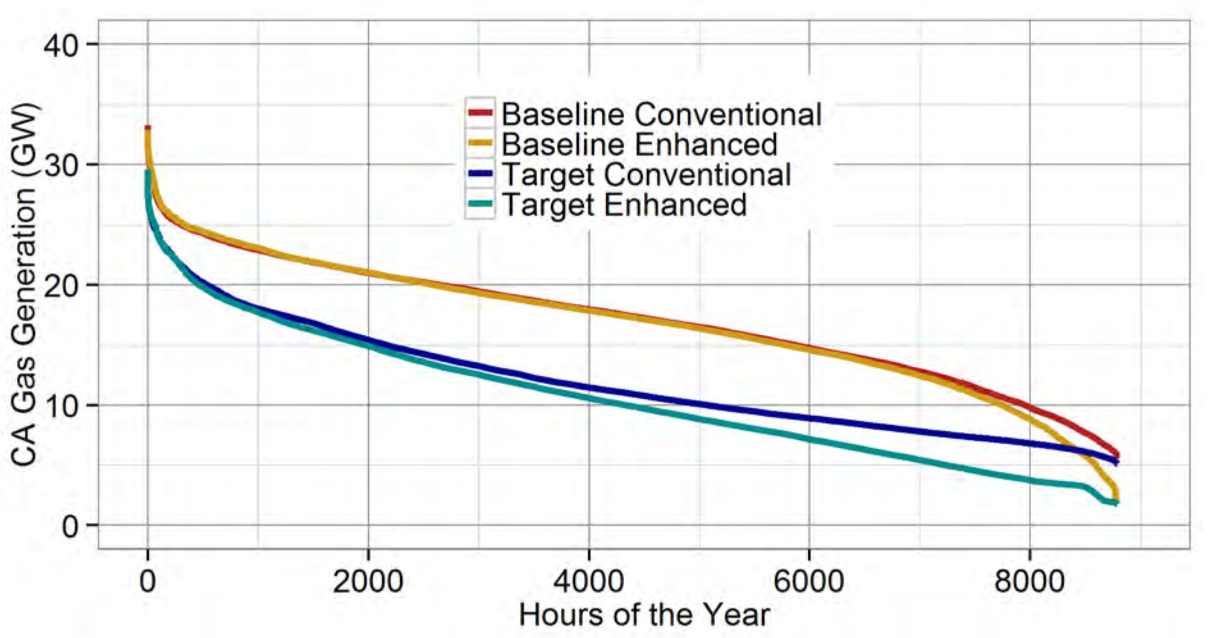


Figure 8. Duration curve of California gas generation for the core scenarios

Table 11 shows that the largest difference in gas operation comes from a lowering of the capacity factor of combined-cycle units in the Target portfolio. This is due to displacement of fossil-fueled resources by the renewables that have zero marginal costs. The combined-cycle units are also operated for fewer hours per start in the Target scenarios.

When the units are online, the average output is similar between scenarios; average output when gas CC units are committed is between 81% and 88% of capacity for all of the core scenarios. This metric indicates the efficiency of the gas fleet dispatch. A higher committed capacity factor indicates that generators are operating closer to their maximum output where, generally, they operate the most efficiently. For comparison, analysis of EPA Continuous Emissions Monitor data shows that in 2013, California combined-cycle units averaged about 80% of capacity when online. In the Target Enhanced scenario, gas CCs are online for an average of 28 hours per start, compared to 48 hours in the Baseline scenarios, indicating more frequent cycling in the Target portfolio.

Table 11. Gas Fleet Statistics for the Core Scenarios

	Capacity Factor (%)		Average Output when Committed (%)		Hours Online per Start (h)	
Scenario	**CC**	**CT**	**CC**	**CT**	**CC**	**CT**
Baseline Enhanced	46	10	86	83	48	6
Baseline Conventional	46	10	84	83	49	6
Target Enhanced	30	7	88	82	28	5
Target Conventional	32	6	81	78	35	6

Figure 9 shows five days of gas-fleet dispatch in the core scenarios on low-demand days in April. On each panel, the line is the online capacity for each generator type, whereas the shaded region below the line is the output from the relevant generator type. CHP-QFs are not included in this chart, which is why gas generation appears to go all the way to zero at times in the Target Enhanced scenario. This chart shows that in all cases, some gas CC units are shutting down every day during the mid-day hours when prices are low due to solar generation. In the Target Enhanced scenario, almost all gas generation (except QFs) is shutting down during mid-day. In the Target Conventional scenario, the minimum local generation rules require that some of the gas generation is generating at all times, which is why the CC dispatch is different at night between the conventional and enhanced flexibility assumptions.

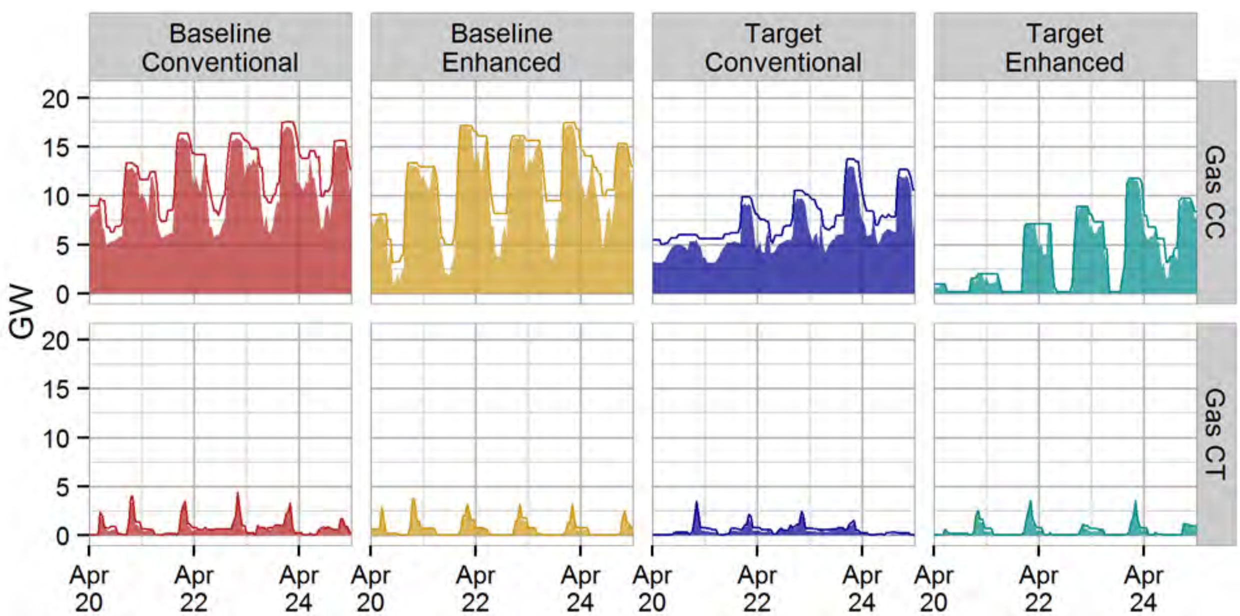


Figure 9. Gas-fleet committed capacity (solid line) and dispatch (shaded region) for five days in April

4.1.7 Ancillary services are provided by a variety of sources

Figure 10 shows the source of the reserve provision for spinning and regulating reserves in the real-time model runs. A variety of sources are used to provide ancillary services in all of the scenarios. The conventional flexibility cases were constrained on which hydro and pumped-storage units could provide reserves so that the results would be similar to the hydro category in the CAISO 2013, which showed about 500 MW on average of procurement from hydro resources in CAISO. In the enhanced flexibility cases, these constraints were relaxed so that the capacity of hydro and storage allowed to provide reserves was about double that in the conventional flexibility cases.

Reserve provision is an example of a situation where the flexibility assumptions impact the results more than the portfolio. Other than the CSP-TES units that are providing reserves in the Target Enhanced Flexibility case, both of the enhanced flexibility cases are very similar for reserve procurement and the both of the conventional flexibility cases are similar. The primary difference is that hydro and storage provide more reserves in the enhanced flexibility cases because they are less constrained. Natural gas units provide reserves in all cases, but provide a majority of the reserves in the conventional cases. There is no unserved load in any of the 23 scenarios that were modeled, and unserved reserves are significantly less than 1 GWh and 0.01% of the total reserve provision in all scenarios (including the sub-hourly runs).

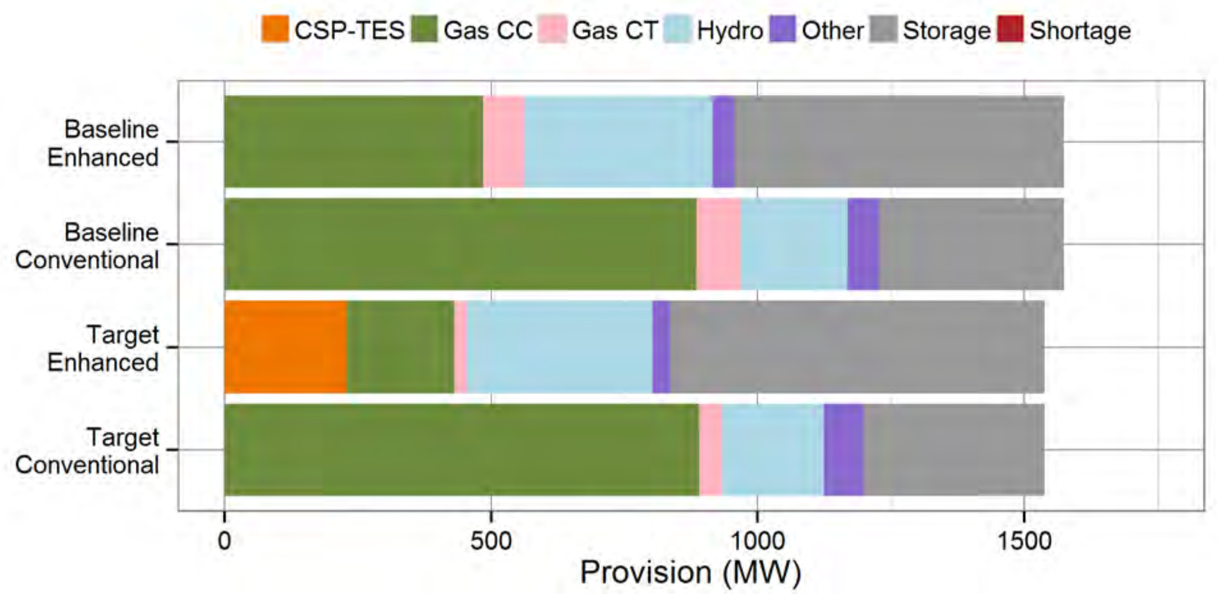


Figure 10. Sources of ancillary services (spinning and regulating reserves) in the real-time market

Flexibility reserves are held in the day-ahead and intra-day unit commitment model, and then released to provide energy when the forecast error is realized in the real-time market. These reserves are intended to provide energy for times of forecast error, so they are allowed to provide energy (and not held back for reserve) in real time. The distribution of resources procured for flexibility reserves is very similar to the regulation and contingency reserves; in fact, many of the resources that are providing flexibility reserves in the day-ahead may provide contingency or regulating reserves in the real-time.

The amount of flexibility reserves required by the model was determined using the methodology from the WWSIS-2 study, and it depends on 60-minute forecast errors for wind and solar and 30-minute forecast errors for load (Liu 2014). This methodology is not identical to what CAISO uses, and it produces annual average flexibility reserve requirements (1,170 MW) that are lower than CAISO LTPP 2014 assumptions for Load Following Up (1,650 MW). In this study, because we modeled unit commitment and economic dispatch in real time, we model both the procurement and actual usage of the flexibility reserves, ensuring that there are sufficient reserves in the model to respond to a realistic amount of forecast error.

4.1.8 A variety of technologies provide flexibility during difficult operating periods

Analysis of several difficult operating periods can demonstrate how the system could provide the needed flexibility under various operating conditions. Figure 11 shows the daily operation of the main sources of dispatch flexibility in the system on February 8, which contains the steepest net load (load minus wind and PV) ramp of the year. This ramp occurs between 3 and 4 pm PST,[14] and the 11 GW increase in net load is almost entirely caused by sunset and the reduction of solar PV generation. A variety of different technologies are ramping during that hour to serve the net load ramp. Table 12 shows the ramping statistics for each category during the maximum net load ramp using the enhanced flexibility assumptions. The ramp is being served by a variety of technologies, with physical imports, storage, and the gas fleet providing the large majority of the ramping. Demand response (mostly EV charging) and hydro generation provide very little during these hours. The EVs provided some ramping (by stopping all charging) from 2 pm to 3 pm, but all charging had stopped at 3 pm and there was no more ability to provide ramping. The hydro generation is constrained such that it was unable to provide significant ramping during any time on February 8. The net load stays much higher in the Target Conventional Flexibility scenario (not shown here) due to minimum import requirements, less storage generation, and minimum local generation requirements. Although the net load goes below 0 in the enhanced flexibility assumptions (due to storage and EV charging), net load never goes below 7,500 MW and the net load ramp is less steep in the conventional flexibility assumptions.

[14] Modeled times noted here represent the average of the hour following the time stamp. This ramp represents the change between the net load average between 3 and 4 pm and the net load average between 4 and 5pm.

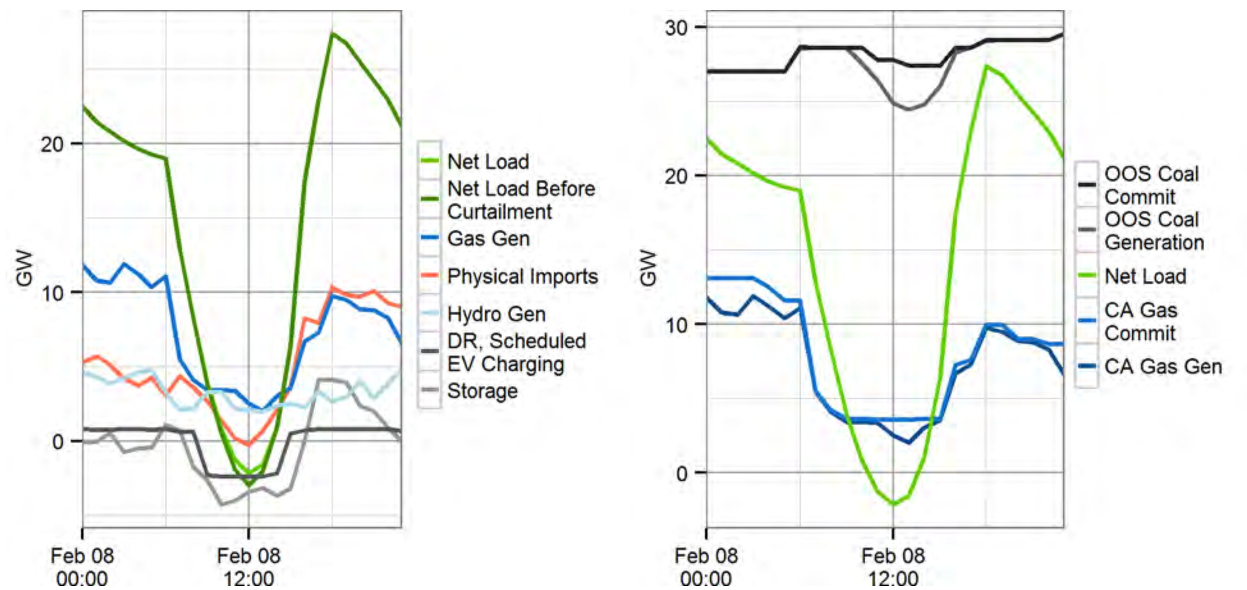


Figure 11. Dispatch during the steepest net load ramp of the year in the Target Enhanced Flexibility scenario. The left plot shows all sources and the right plot focuses on in-state gas generation and out-of-state coal generation.

Figure 11 also shows that the net load continues to rise between 4 pm and 6 pm, due to the increase in load associated with lighting and other energy consumption often seen during early evening in winter. This ramp is also served mostly by physical imports, natural gas generation, and storage (from 4 pm to 5 pm). There are other steep ramps during the year that are served primarily by one of these main three sources, but most of the steep ramps are provided primarily by a combination of those three sources.

Table 12. Ramping Statistics Between 3 pm and 4 pm on February 8 in the Target Enhanced Flexibility Scenario

Technology	MW Ramp between 3 pm and 4 pm (MW)
Physical imports	4,550
Storage	3,230
Gas-fleet dispatch	3,150
Demand response (mostly schedulable EV charging)	240
Hydro generation dispatch	-250

Figure 12 shows the distribution of ramps (positive numbers are up-ramps, negative numbers are down-ramps) along four selected interfaces in the Target Enhanced Flexibility scenario. The average of the top 5% of up-ramp hours is 1,400 MW/h in the Target scenario for the California-Oregon Interface (COI, Path 66) plus the Pacific DC Intertie (PDCI, Path 65). In 2010, these top 5% hours ranged from about 800 to 1,600 MW/h on this interface, depending on the month. The average of the top 5% of up-ramp hours is 1500 MW/h in the Target scenario for the West of Colorado River path (WOR, Path 46), compared to 500–1,100 MW/h in 2010, depending on the month. Although the COI+PDCI interface in the Target scenario has similar historical precedent, the ramping on West of Colorado River (Path 46) is higher in the modeled scenarios than it was in 2010 during any month of the year. Although the model included physical constraints of the transmission paths and the generators on both sides of the path, there could be institutional constraints (e.g., bilateral contracts) that make ramping on these paths more difficult in reality. For this modeling, it is assumed that these constraints (beyond what is represented by the hurdle rates between regions) no longer exist in 2030 due to institutional changes (e.g., renegotiating bilateral contracts). Interface ramping was similar in most of the scenarios. The California portfolio had modest impacts on coal cycling out of state; other assumptions (out-of-state renewable penetration, gas prices, and hydro conditions) had much larger impacts on coal cycling (see Appendix for modeling results for out-of-state generators).

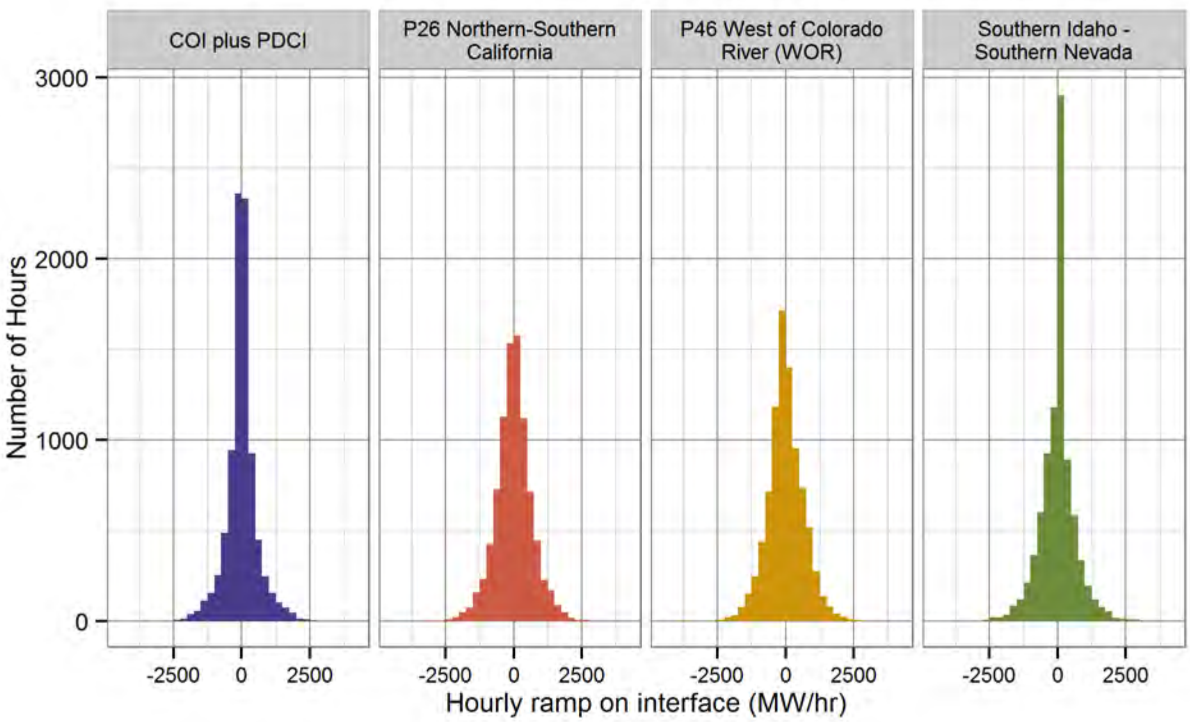


Figure 12. Ramping statistics on four major interfaces in the Target Enhanced scenario.

Another interesting set of conditions to analyze are conditions with very low net load (and high curtailment). May 30 at noon is the peak curtailment hour in the Target Enhanced Flexibility scenario. Figure 13 shows the dispatch during this day. Although net load could have gone to -5 GW, curtailment prevented it from dipping below -2 GW. The demand response and storage provide the ability for the net load to go below 0, and minimum generation levels from the thermal fleet (including some curtailed CHP-QFs). The ramp is not nearly as steep, but the system does ramp over 20 GW of net load in 5 hours. This ramp is provided by physical imports, storage, demand response, and gas generation. The imports provide the largest amount of ramping, and the out-of-state coal commitment and dispatch are shown on the right side of Figure 13. Coal generation shows significant ramping (ramping online capacity, not starting new capacity) from 3 pm until 5 pm. This ramp causes coal generation to ramp about 15% of its online capacity per hour, which is a reasonable rate for most coal generators.

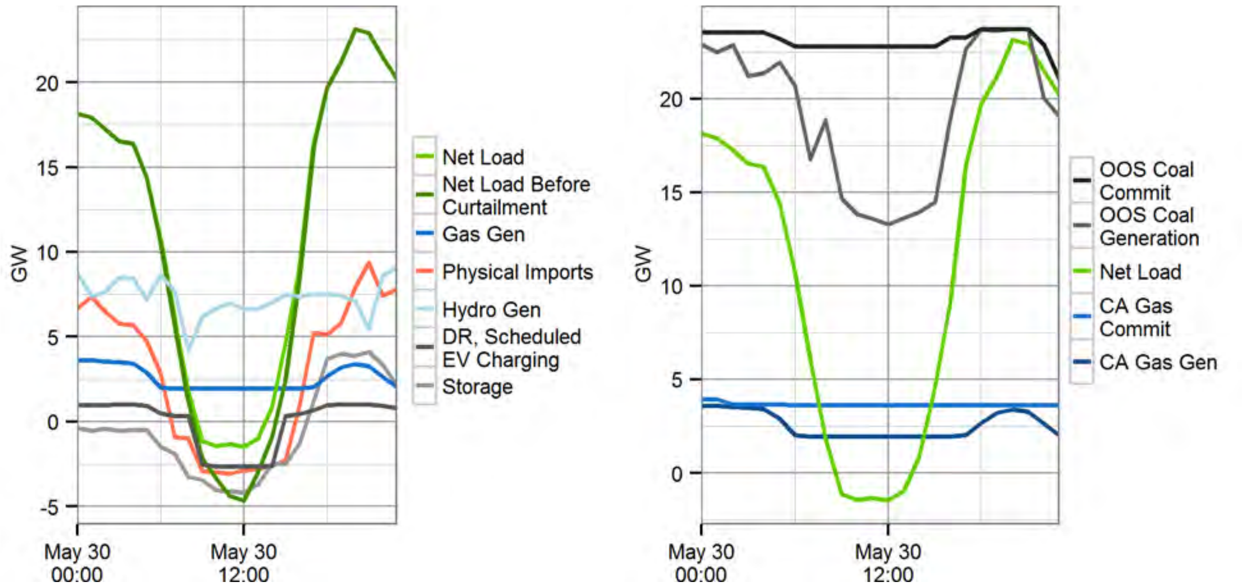


Figure 13. Dispatch during the maximum curtailment day in the Target Enhanced Flexibility scenario. The left plot shows all sources and the right plot focuses on in-state gas generation and out-of-state coal generation.

An example of this same day (May 30) with conventional flexibility assumptions and the High West renewable penetration outside California follows in section 4.2.1.

4.2 Impact of Key Assumptions

This section analyzes the particular drivers and their relative importance for some of the key metrics reported earlier. In addition to the four core scenarios, there are 19 additional scenarios that test the impact of specific assumptions included in the conventional and enhanced flexibility framework, portfolio changes within and outside California, gas and CO_2 prices, locked day-ahead energy schedules, and hydro conditions. All results are presented in 2014 dollars.

4.2.1 The main conclusions of the modeling are not impacted by achieving higher penetrations in the rest of the western United States

California is well-linked with the rest of the Western Interconnection. In 2013, almost one-third of the electricity consumed in California was generated out of state. Because California is impacted by the conditions in the rest of the Western Interconnection, we created several scenarios that included portfolios outside of California that had much higher penetrations of EE and RE. This portfolio is described in more detail in section 2.1, and it represents about 35% penetration of RE (as a fraction of load, including transmission and distribution losses) outside of California. This case represents a future in which states outside of California go beyond existing RPS legislation or install a significant amount of renewable generation in response to other policies, such as EPA's section 111 (d) requirements.

This portfolio was included with three scenarios: the Baseline Enhanced, Target Enhanced, and the Target Conventional. Table 13 shows the impact of increasing renewable penetrations outside of California; these scenarios are referred to as "High West Penetration." None of the major conclusions of the study (e.g., production cost changes, curtailment, CO_2 emissions for the different scenarios) for California are different in the High West Penetration scenarios, compared to the comparable scenarios. The largest difference is in net imports to California, which go up due to the lower price of electricity outside of California due to the presence of additional zero-marginal cost resources. This also leads to lower capacity factors of California gas generators. Production costs outside of California were reduced significantly, as were CO_2 emissions throughout the Western Interconnection. Because unspecified imports of out-of-state fossil-fueled generation are a small percentage of generation in the Target scenarios, the modeling did not show any cost reductions in California from the High West penetration. See Appendix for details on specific categories of production cost.

More work needs to be done to understand high-penetration scenarios throughout the Western Interconnection. The modeling for LCGS was focused on producing high-fidelity results for impacts in California, and so the assumptions (e.g., renewable portfolio, zonal transmission representation) may need to be refined outside of California for studying the western United States in greater detail. Very low capacity factors of CC generators, particularly in the Target Enhanced High West scenario in California, may indicate a need for more work to understand local generation requirements.

Table 13. Key Results in the High West Scenarios

Scenario	CA Production Cost Savings from Baseline (billion $)	Curtail-ment (%)	Annual Net Imports (TWh)	CO_2 Assigned to CA Load (MMT)	CA Gas CC Capacity Factor (%)
Baseline Enhanced	-	0.0	56.8	74.4	46.1
Baseline Enhanced, High West	0.24	0.0	80.3	72.9	37.7
Target Enhanced	4.85	0.2	60.5	41.1	30.0
Target Enhanced, High West	4.96	0.7	64.7	43.2	20.5
Target Conventional	4.30	4.2	56.1	45.0	31.9
Target Conventional, High West	4.47	4.9	66.6	45.1	26.9

Figure 14 shows the dispatch on a challenging day in the Target Conventional Flexibility High West scenario. The left plot shows over 20 GW of curtailment due to the conventional flexibility assumptions. The right plot shows the response of out-of-state coal generation to the system ramping requirements (which includes transmission to California and higher levels of out-of-state renewable penetration). Compared to the Target Enhanced scenario dispatch (Figure 13), there is about half as much coal generation online at the beginning of the day, but most of it shuts down as the sun rises in the High West scenario. In the Target Enhanced scenario, coal generation ramps down at sunrise, but very little of the coal capacity shuts down. With the higher renewable penetrations west-wide, coal generation is often shut down due to displacement by renewable resources. Coal capacity factors outside California reduce from 86% to 56% in response to the High West penetrations and hours online per start goes from over 600 to close to

300 hours, assuming enhanced grid flexibility (although the relative differences are similar for conventional grid flexibility scenarios). The Appendix has additional information on dispatch outside of California for these scenarios.

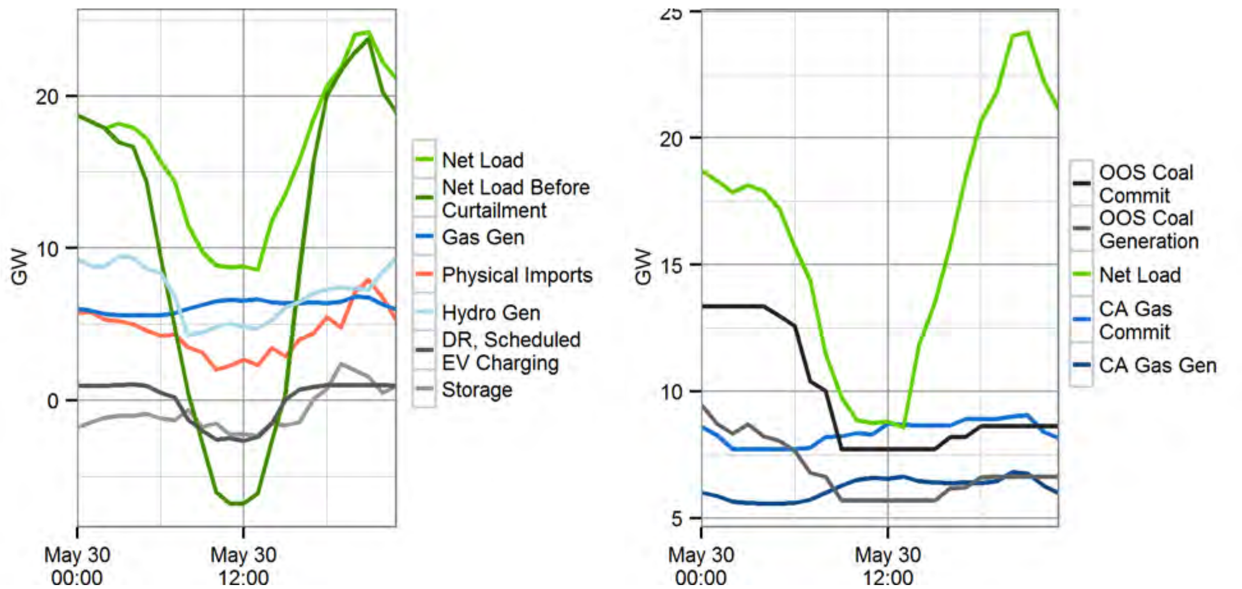


Figure 14. Dispatch during the maximum curtailment day in the Target Conventional High West scenario. The left plot shows all sources and the right plot focuses on in-state gas generation and out-of-state (OOS) coal generation.

4.2.2 Higher solar penetrations could lead to 10% curtailment if institutional framework remains inflexible

High penetrations of solar can be challenging to integrate for systems that do not have sufficient flexibility options such as exports, storage, and demand response. This is because the solar generation is very well correlated throughout the region due to the path of the sun. Figure 15 shows the average annual diurnal pattern of curtailment in the Target core scenarios and the Target High Solar scenarios. PV penetration in the Target portfolio is about 20% (before curtailment, and including rooftop and utility-scale), whereas PV penetration in the Target High Solar is 28%.

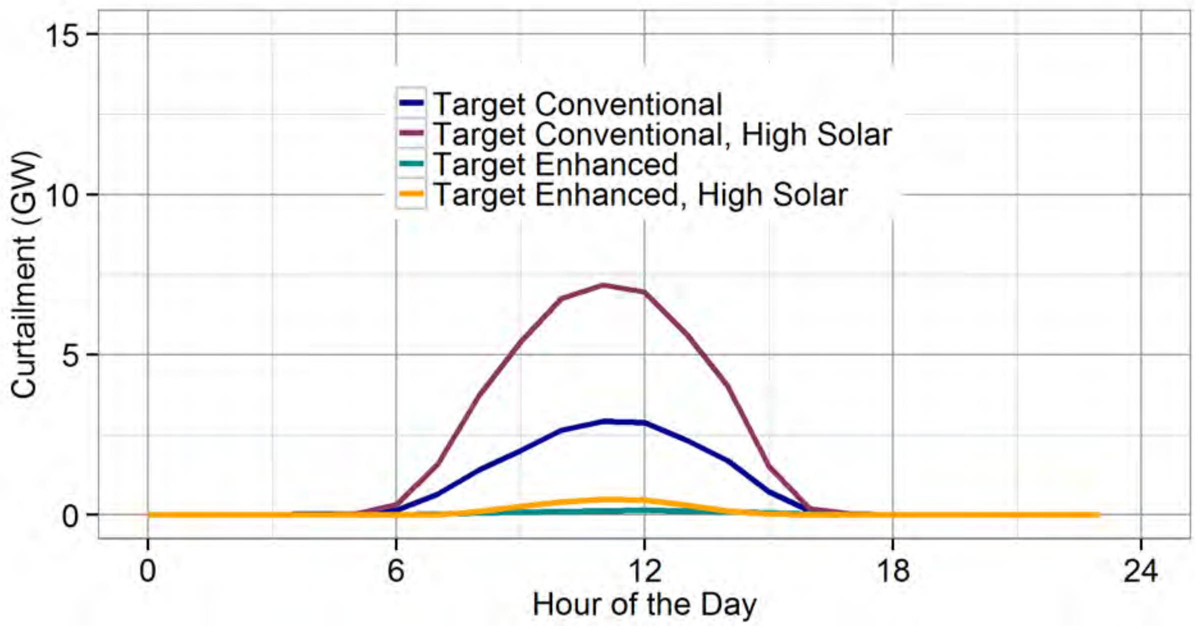


Figure 15. Diurnal curtailment pattern for High Solar scenarios

With enhanced flexibility assumptions, the power system has the ability to displace more imports, sell more power, store energy, and turn down the thermal fleet. Under these conditions, integrating additional solar energy does not lead to large changes in curtailment or CO_2 emissions. Curtailment increases from 0.2% to 0.5% and production costs savings go down $200 million in the High Solar scenario. Curtailment explains some of the production cost differential, but the High Solar scenario also has more generation during low-price (mid-day) hours when solar generation has already displaces the higher-cost resources. Table 14 shows the key results of the study in the High Solar scenarios.

Table 14. Key Results with High Solar Scenarios

Scenario	Production Cost Savings from Baseline Enhanced (billion $)	Curtail-ment (%)	Annual Net Imports (TWh)	CO_2 Assigned to CA Load (MMT)	CA gas CC capacity factor (%)
Target Enhanced	4.85	0.2	60.5	41.1	30.0
Target Enhanced, High Solar	4.64	0.5	52.5	42.2	27.2
Target Conventional	4.30	4.2	56.1	45.0	31.9
Target Conventional, High Solar	4.07	9.7	58.6	46.8	32.5

In the conventional assumptions, it is much more challenging for the grid to integrate the additional PV in the High Solar portfolio. Figure 15 shows the diurnal pattern of the curtailment in the High Solar scenarios. In the Target Conventional scenario, curtailment is clearly driven by solar PV generation, as it peaks slightly before noon and there is no curtailment between sunset and sunrise. The incremental PV in the High Solar scenario adds generation during the lowest-price, highest-curtailment hours. The additional solar increases curtailment from 4.2% to 9.7% and reduces production cost savings by $230 million. Due to the curtailment, the CO_2 reduction is 2–3 MMT less with the High Solar portfolio in the conventional framework compared to the enhanced framework. The system stress caused by very high solar PV penetrations could potentially be more significant if some of today's operational practices are continued and flexibility is even more limited than the conventional flexibility assumptions used for this study (see Table 5).

4.2.3 Requirements on importing out-of-state zero-carbon energy could increase curtailment, costs, and carbon

In the Target scenarios, some of the zero-carbon energy comes from out-of-state sources in all of the portfolios. As discussed in section 4.1.4, in most of the scenarios, California-entitled generation that is sold out of state, a proxy for unbundled RECs, makes up less than 10% of the zero-carbon energy in all of the scenarios (except the Target low gas / high carbon cost). However, to ensure that most of this energy is coming into California during every hour, we included a 70% import requirement in the conventional flexibility suite of assumptions. This is consistent with CAISO modeling (Liu 2014) and requires that California must be importing at least 70% of all out-of-state California-entitled generation at every hour. The 70% rule eliminates net exporting from California in cases that include this constraint. When the 70% rule was binding, the model typically curtailed out-of-state renewable generation while importing 70% of the possible generation from Hoover Dam and Palo Verde Nuclear Generating Station.

To understand the effect of this rule in both flexibility constrained and unconstrained systems, a 70% rule sensitivity was run on both the Target Enhanced and Target Conventional scenarios. Table 15 shows the key results, including the specified imports that are sold out of state. Adding the 70% import rule to the Target Enhanced Flexibility scenario had modest impacts. Curtailment went from 0.2% to 0.9%, and import, carbon, and production cost numbers showed similar changes. However, removing the 70% rule from the Target Conventional Flexibility case had more significant impacts. Curtailment was reduced from 4.2% to 0.6%, imports and carbon emissions went down, and the specified imports sold out of state went from 4.8 TWh to 14.2 TWh. Production cost savings were about $500 million higher in the case without the import requirement. Allowing specified imports to be sold out of state is the functional equivalent of allowing physical exports from California but is less expensive because it may save transmission costs (represented by a hurdle rate in this study).

Table 15. Key Results for Out-of-State Import Requirement Sensitivities

Scenario	Production Cost Savings from Baseline (billion $)	Curtail -ment (%)	Annual Net Imports (TWh)	CO_2 Assigned to CA Load (MMT)	CA Gas CC Capacity Factor (%)	Specified Imports that are Imported (TWh)
Target Enhanced	4.85	0.2	60.5	41.1	30.0	5.1
Target Enhanced, With Import Rule	4.71	0.9	61.7	41.8	29.8	3.0
Target Conventional	4.30	4.2	56.1	45.0	31.9	4.8
Target Conventional, No Import Rule	4.81	0.6	47.6	42.3	31.9	14.2

Figure 16 shows the duration curve of unspecified imports. During times when California is importing a significant amount of generation, the cases all operate similarly. However, the rules become binding during hours when California is importing less. The cases that include the 70% import rule operate similarly because the constraint binds and does not allow much California-owned generation to be sold out of state.

In the enhanced flexibility framework, there are many flexibility options, and including an import requirement has a modest impact. Because of the constrained flexibility in the conventional framework, removing a binding constraint (the 70% import rule) made a significant difference. This suggests that a policy to limit the use of unbundled RECs could increase curtailment and carbon emissions if the system is flexibility-constrained.

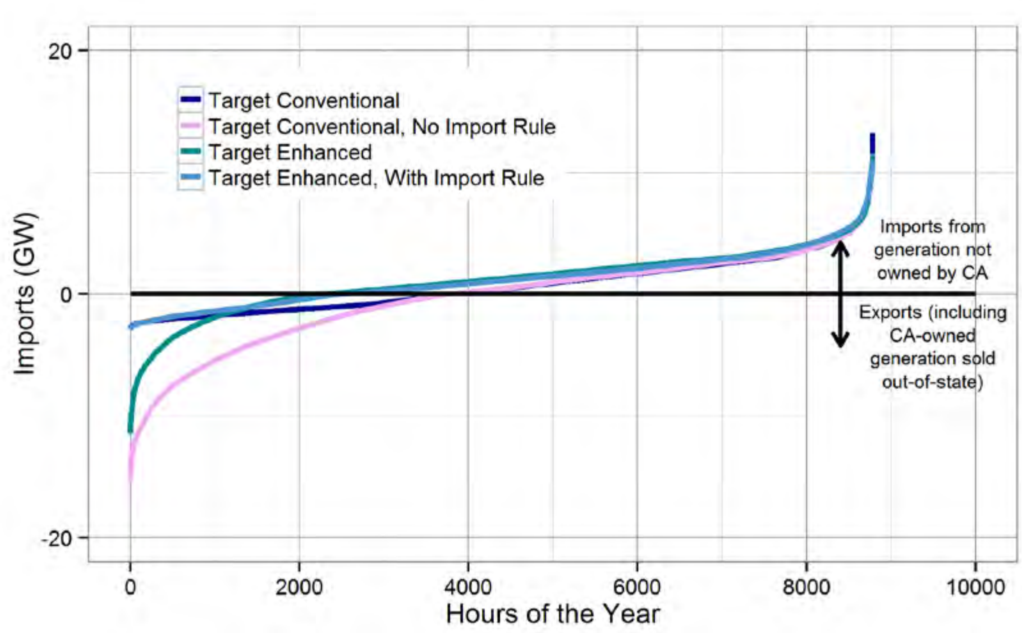


Figure 16. Unspecified imports in the import rule sensitivities

4.2.4 Local generation requirements could increase curtailment and costs

The CAISO and WECC are currently enforcing a "local generation requirement" in California for planning studies. The local generation requirement addresses the general issue of maintaining adequate frequency response and transient stability to ensure grid reliability as traditional synchronous generation is replaced with inverter-based generation such as wind and PV and there is greater reliance on battery storage and HVDC transmission. The issue is the subject of significant research and product development around the world with significant visible efforts ongoing in, for example, Electric Reliability Council of Texas (ERCOT), Ireland, Australia, and Germany with tangible results expected in the 3–5-year time frame.

The issue for the LCGS is that relying on thermal generation to meet the 25% rule crowds out renewable generation and increases curtailment of renewables in low-load hours. The modeling done here with and without the 25% rule as currently contemplated by the CAISO demonstrates that, although it is possible to meet the 2030 greenhouse gas reduction targets with the 25% rule in place, it is expensive—production cost differentials due to the 25% rule are $200 million–$400 million per year, depending on the flexibility framework. More importantly, this constraint becomes ever-more binding as greenhouse gas targets are lowered in the future because the 25% minimum requirement puts a floor under gas generation and thus greenhouse gas emissions. The problem is particularly acute in the Target High Solar scenario due to the dearth of synchronous renewable generation such as geothermal, biomass, and CSP. Alternative solutions to meeting reliability requirements (other than the 25% rule) will be necessary in order to meet California's long-term (2050) climate goals for the electric sector. These dynamic grid issues, and the alternative solutions, are the subject of a GE white paper as part of the LCGS project (Miller 2015). The 25% rule is a proxy for many of these grid issues, and it is likely that there are lower-cost ways to achieve these services, including synchronous condensers, synthetic inertia, and allowing resources outside of load pockets to provide these services when conditions allow. Any costs that may arise from alternative solutions to these dynamic grid issues are uncertain and not included in this analysis.

The local generation requirement used for this study was implemented as a requirement that 25% of the generation in four California balancing authorities (LADWP, SCE, SDG&E, and the Bay Area portion of PG&E) come from fossil-fueled and pumped hydro storage generators within that balancing authority. The rule implemented for this study was consistent with the WECC TEPPC 2024 Common Case assumptions; the rule is a proxy for various grid services and it is evolving continually and defined differently in other studies. The CAISO LTPP implementation of the rule includes other balancing authorities but not the Bay Area portion of PG&E.

Table 16 shows the key results for the local generation sensitivities. In the enhanced flexibility cases, the impacts of the local generation requirement were seen mostly on imports; the additional local generation caused by the requirement displaced imports. In the conventional flexibility cases, there is a significant difference: $400 million for production cost, three percentage points for curtailment, and a 3 MMT difference in carbon emissions.

Table 16. Key Results for Local Generation Requirement Sensitivities

Scenario	Production Cost Savings from Baseline (billion $)	Curtail-ment (%)	Annual net imports (TWh)	CO_2 Assigned to CA Load (MMT)	CA Gas CC Capacity Factor (%)
Target Enhanced	4.85	0.2	60.5	41.1	30.0
Target Enhanced, With 25% Gen Rule	4.68	0.5	49.0	42.2	32.8
Target Conventional	4.30	4.2	56.1	45.0	31.9
Target Conventional, No 25% Gen Rule	4.71	1.2	61.3	42.2	27.0

Figure 17 shows the gas generation (not including CHP-QFs) in the conventional flexibility cases. Dispatch during the evening and overnight hours, when gas operates the most, is similar between the two cases. However, during the mid-day hours, a significant amount of CC generation is kept online in the case with 25% local generation requirement; but in the case without the 25% local generation requirement, most of the generation is shut down during those mid-day hours.

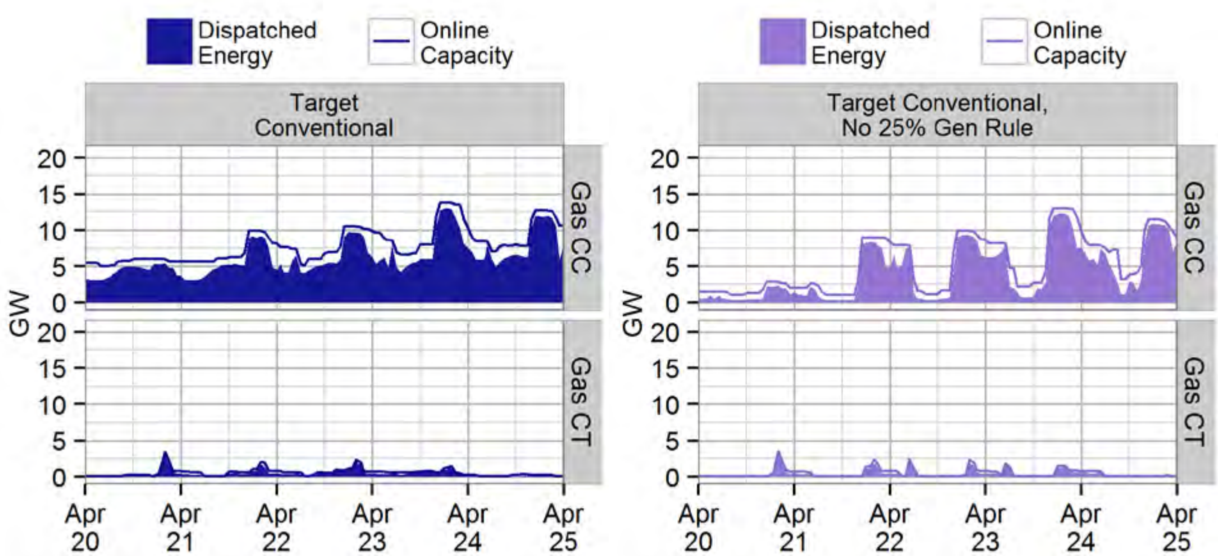


Figure 17. Committed and dispatched capacity for the Target Conventional scenario with and without the 25% local generation requirements

4.2.5 Efficient day-ahead scheduling is important; locking exports and imports from the day-ahead market increases curtailment by 1%

Efficient exchange of power in the day-ahead market is important for economic reasons, as noted by CAISO and others (Liu 2014, Lew et al 2013). We tested a case where the day-ahead interchange schedules were locked for the real-time market, simulating a market where there was very little flexibility in the real-time market. California ISO is already moving forward with developing a full real-time market with the Energy Imbalance Market (EIM) including PacifiCorp and NV Energy, and also Arizona Public Service and Puget Sound Energy in 2016. This scenario with the locked day-ahead schedules will analyze a future where the EIM does not expand or does not trade significant amounts of power in the real-time market. In this scenario, all balancing that occurs for California (based on forecast errors) during real-time dispatch must occur within California rather than the least-cost resources throughout the Western Interconnection. This assumption and this scenario are intended as a proxy to understand the impacts of inefficient real-time trading; reality will likely be more flexible than fixed schedules and less flexible than full re-dispatch of the interface flows.

The impact of this assumption on key results is in Table 17. Production cost savings are reduced by $100 million, curtailment increases by a percentage point, and carbon increases by almost 2 MMT if the day-ahead schedules are locked. Imports are also significantly reduced, because California optimally imports more in the real-time market (compared to day-ahead) in the model. The reason for this is the uncertainty in day-ahead load and variable generation forecasts that inform unit commitment and balancing authority interchange schedules that become difficult to adjust in real time. Although real-time flexibility of power exchange helps to reduce costs and curtailment, a low-carbon grid is still possible when interchange schedules are locked day-ahead.

Table 17. Key Results for the Impact of Locked Day-Ahead Schedules

Scenario	Production Cost Savings from Baseline (billion $)	Curtail-ment (%)	Annual Net Imports (TWh)	CO_2 Assigned to CA Load (MMT)	CA Gas CC Capacity Factor (%)
Target Conventional	4.30	4.2	56.1	45.0	31.9
Target Conventional, With Locked Day-Ahead Imports	4.20	5.4	47.5	46.8	32.2

4.2.6 Storage and demand response could help reduce operational costs and curtailment in scenarios where institutional flexibility is constrained

Additional storage and demand response were tested in the Target Conventional scenario to determine if the additional flexibility would be valuable in a flexibility-constrained system. We added 2 GW of pumped hydro storage and assumed that DR reached “theoretical availability” levels compared to “projected availability,” as classified by Olsen et al. (2013). The Appendix contains more information about these DR classifications. This scenario helps analyze whether technical solutions, such as storage and DR, can help mitigate curtailment and other issues if the institutional framework is more constrained.

Figure 18 shows the dispatch of storage and demand response in the Target Conventional cases with and without the extra storage and DR. During the summer (defined as June through August for this plot), the flexibility is used more than other times, because the prices are low during noon hours and capacity is needed after sunset. Outside of summer, the ability to arbitrage energy is less valuable and used less often, and shiftable loads such as space cooling are not available.

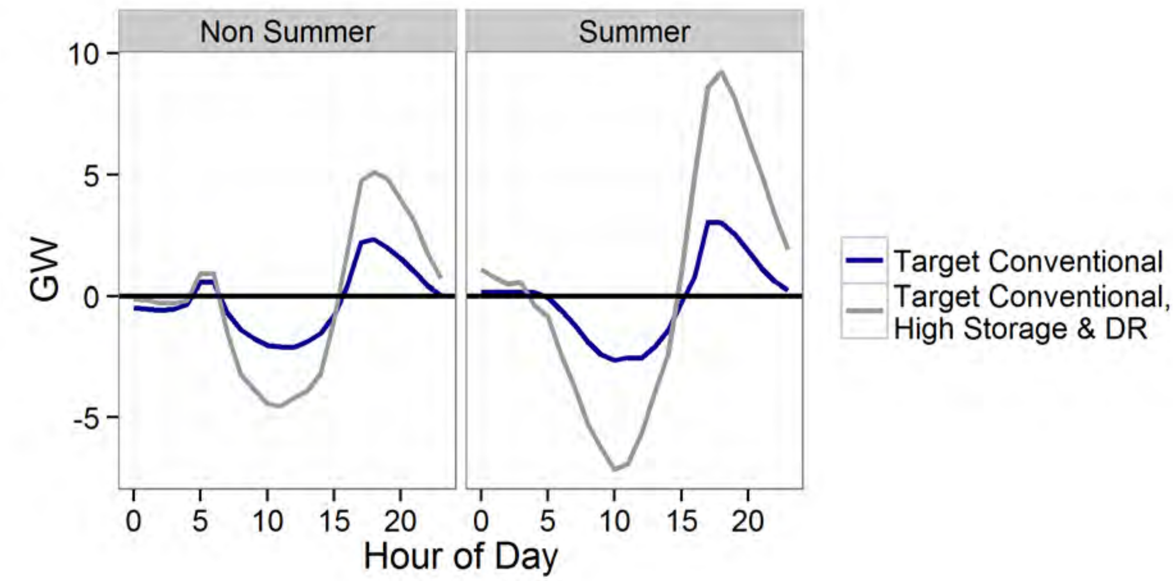


Figure 18. Storage and DR dispatch (generation is positive) for the Target Conventional with and without additional storage/DR

Table 18 shows the key results for the additional storage and DR scenario. The additional flexibility is used for curtailment reduction, but it is also used to reduce production costs independent of the curtailment. Most of the other flexibility options considered before this section reduce production costs by about $100 million per percentage point of curtailment reduced. Adding DR and storage, as in this case, reduces curtailment by 1.1% and production costs by $700 million. This indicates that DR and storage are used for arbitrage even during times when curtailment does not occur, which reduces production cost and emissions without impacting curtailment.

Table 18. Key Results for the Impact of Storage and Demand Response

Scenario	Production Cost Savings from Baseline (billion $)	Curtail-ment (%)	Annual Net Imports (TWh)	CO_2 Assigned to CA Load (MMT)	CA Gas CC Capacity Factor (%)
Target Conventional	4.30	4.2	56.1	45.0	31.9
Target Conventional, With High Storage + Demand Response	4.98	3.1	54.3	41.7	30.8

The additional storage also creates the potential for more losses since the storage devices modeled here operate at 75% efficiency. Some of the losses associated with increased usage of storage during times of curtailment is comparable to increased curtailment, because this lost energy does not displace any non-renewable generation. In all of the cases that do not have higher penetrations of renewables outside California (see section 4.2.1), there is no more than 1 TWh of additional storage losses in the Target scenario compared to the comparable Baseline scenario, which is equivalent to 0.3 percentage points of curtailment. The exception is the Target Conventional with additional Storage / DR scenario, which sees close to 2 TWh of additional storage losses compared to the Baseline portfolio, which does not have the extra storage capacity. These additional losses are not counted as curtailment for this study.

Storage and demand response also reduce cycling at fossil-fueled generators. In the model, gas CC units in California were online for 35 hours per start on average in the Target Conventional scenario compared to 53 hours when more storage and demand response were added. For comparison, the enhanced flexibility assumptions led to more cycling and an average online time of 28 hours per start in the Target Enhanced scenario. For more details on cycling in all scenarios, see the Appendix.

4.2.7 Hydropower availability does not have a large impact on total renewable curtailment, but it does impact total carbon emissions

Available hydropower can vary significantly between years. We ran wet and dry hydro sensitivities to understand whether hydro availability had a significant impact on the key results, such as wet hydro impacting curtailment or dry hydro leading to missing a carbon goal.

The 2005 hydro generation levels were the basis for most of the scenarios. WECC uses these data as representative of a typical year. We tested the impact hydro availability by substituting estimates from 2001 (a dry year) and 2011 (a wet year). Regional multipliers were used for both monthly energy and capacity. See the Appendix for more details on the methodology and monthly breakdowns of hydro changes. Figure 19 shows the change in hydro in the wet and dry scenarios. Note that the multipliers are applied to five regions throughout the western U.S., not just California. Although the dry case has 30% less hydro availability in California, the wet case has just 8% more hydro in California (but much higher increases outside California).

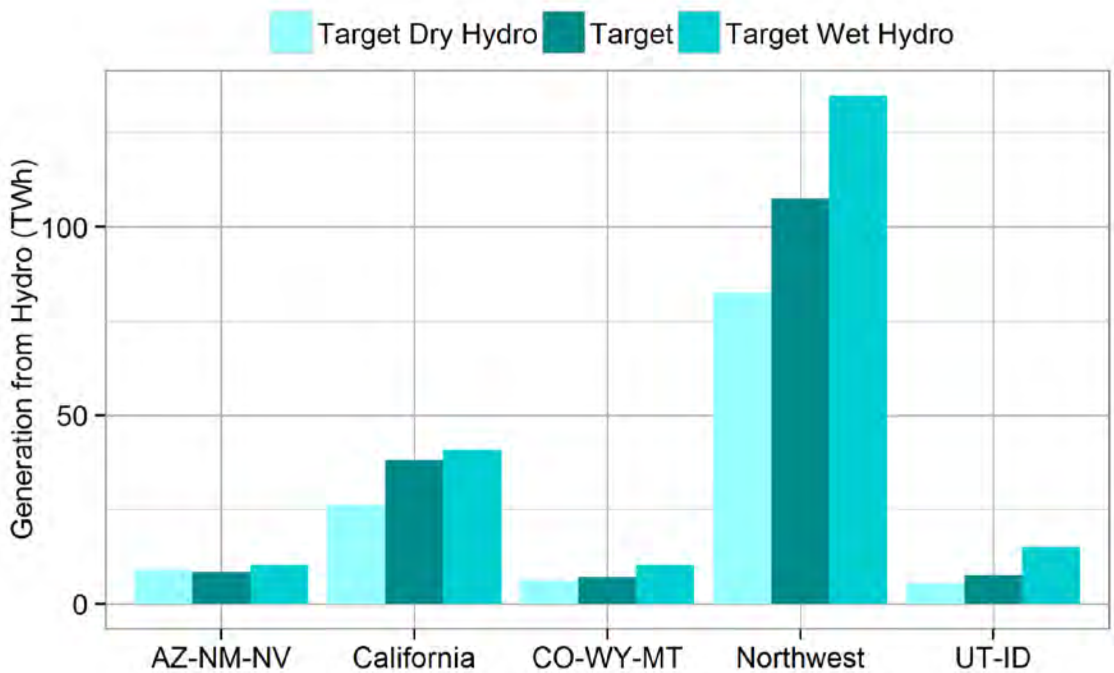


Figure 19. The annual regional generation from hydroelectric generators in the hydro sensitivity cases

Table 19 shows the key results of the hydro sensitivities. Note that production cost savings are not included because wet and dry hydro sensitivities were not run with the Baseline portfolio, and we cannot compare to the Baseline scenario because of the change in hydro generation, a zero marginal-cost resource. As expected, imports go up slightly in wet hydro assumptions and down with dry hydro since California imports energy from the hydro-heavy Northwestern US are tied to availability of the hydro resource. Because hydro generation is zero-carbon, the hydro sensitivities lead to significant changes in carbon emissions assigned to California. Although the Target Enhanced with dry hydro is a 51% reduction below 2012 emissions levels, the Target Conventional with dry hydro scenario shows 50 MMT of carbon emissions due to California load, which is a 47% reduction below 2012 levels and does not meet the goal of a 50% reduction below 2012 levels. To meet the carbon goals in long-term dry hydro conditions, enhanced flexibility or a portfolio with more zero-carbon energy may be necessary.

The hydro generation scenarios had very little impact on curtailment in California. However, the wet hydro sensitivity may understate the issues caused by a wet hydro year in California for two reasons. First, the flexibility of the hydro fleet may be reduced more during a wet year than was modeled here because of stricter operating limits due to the excess water. Second, the west-wide wet hydro year had only 8% more hydropower generation in California compared to 2005. Therefore, even though the modeled year was ‘wet’ for the west as a whole, it was only slightly wetter than normal in California. This topic needs further investigation.

Table 19. Key Results in the Hydro Sensitivities

Scenario	Production Cost Savings from Baseline	Curtail-ment (%)	Annual Net Imports (TWh)	CO_2 Assigned to CA Load (MMT)	CA Gas CC Capacity Factor (%)
Target Enhanced	n/a	0.2	60.5	41.1	30.0
Target Enhanced, Wet Hydro	n/a	0.3	65.2	39.5	27.6
Target Enhanced, Dry Hydro	n/a	0.2	56.3	47.0	30.6
Target Conventional	n/a	4.2	56.1	45.0	31.9
Target Conventional, Wet Hydro	n/a	4.4	58.5	43.7	26.8
Target Conventional, Dry Hydro	n/a	4.2	53.9	50.3	31.9

4.2.8 Increasing carbon costs and reducing gas costs doesn't have much of an effect on curtailment in California but greatly reduces emissions outside California

Because we wanted to model a case where combined carbon and gas costs led to gas substituting for much of the coal generation throughout the west, we assumed that the carbon cost would be applied west-wide in a Target Low Gas / High CO_2 scenario. This makes production cost comparisons with the other cases somewhat difficult, which is why we also ran a Baseline Low Gas / High CO_2 scenario.

Table 20 shows the key results in the low gas and high west-wide carbon cost scenarios. To facilitate comparisons between multiple cases, the production cost column is shown as the total production cost, not as the difference from the Baseline. The costs are shown for California load.

Imports go down by about 40 TWh per year in the low gas and high carbon cost sensitivities. In all low-gas and high-carbon cost scenarios, California-entitled generation sold out of state is larger than the imports of generation owned and contracted out of state (unspecified imports). This is because the efficient (but expensive, in all previous cases) California gas generation is competitive with any out-of-state generation (coal and gas) in these cases. There is no reason for California to import much power (except during peak hours), and often California sells its out-of-state resources in these scenarios to displace the more expensive out-of-state fossil-fueled generation. California gas CC generators have correspondingly higher capacity factors in the low-gas and high-carbon cost scenarios.

CO_2 is shown as west-wide CO_2, because much of the impact of these cases occurs outside California. Using the accounting method, carbon assigned to California load goes up slightly; the results might not be directly comparable because California sells more generation out of state than it imports in these cases (even the Baseline). Total west-wide carbon goes down dramatically from the Baseline scenario due the portfolio changes and the gas/carbon cost changes. The carbon reduction caused by the low gas price and high carbon cost (which causes the Baseline Low Gas / High CO2 scenario to emit 122 MMT less carbon compared to the Baseline) is comparable to the carbon reduction due to the portfolio changes inside and outside California (which cause carbon to be reduced by 138 MMT). The combination of gas prices, carbon costs, and the portfolio changes reduces west-wide carbon by 235 MMT (from 381 to 146 MMT).

Table 20. Key Results in the Gas and Carbon Price Sensitivities

Scenario	California Production Cost (billion $)	Curtail-ment (%)	Annual Net Imports (TWh)	West-wide CO_2 Emissions (MMT)	CA Gas CC Capacity Factor (%)
Baseline Enhanced	12.71	0.0	56.8	380.9	46.1
Target Enhanced	7.87	0.2	60.5	345.1	30.0
Baseline Enhanced, Low Gas / High CO_2	12.30	0.0	20.1	259.0	57.3
Target Enhanced, Low Gas / High CO_2	7.61	0.3	21.6	216.0	37.2
Target Enhanced, High West	7.75	0.7	76.7	243.3	20.5
Target Enhanced, High West, Low Gas / High CO_2	7.44	0.4	39.0	146.0	31.5

The impacts of the low gas and high carbon costs are very significant throughout the western United States, but the impacts on California emissions and curtailment are smaller. The cost reductions of the Target portfolio are comparable to the original gas and carbon cost assumptions, and with the exception of the major drop in imports (and corresponding increase in gas usage), other results for California are similar. Curtailment is small in all low gas and high carbon cost scenarios, which were run with enhanced flexibility assumptions to be consistent with other assumptions that push for lower carbon levels throughout the Western Interconnection. Figure 20 shows the dispatch for the out-of-state resources in the relevant Target scenarios. The low gas prices and high carbon costs lead to a significant shift from coal to gas throughout the west, and overall generation goes down somewhat in the neighboring western states (due to reduction in flows going into California, which is not shown in this plot). When the High West portfolio is added, much of the gas in the west gets displaced with wind and solar, and overall generation goes down again due to energy efficiency in the High West portfolio.

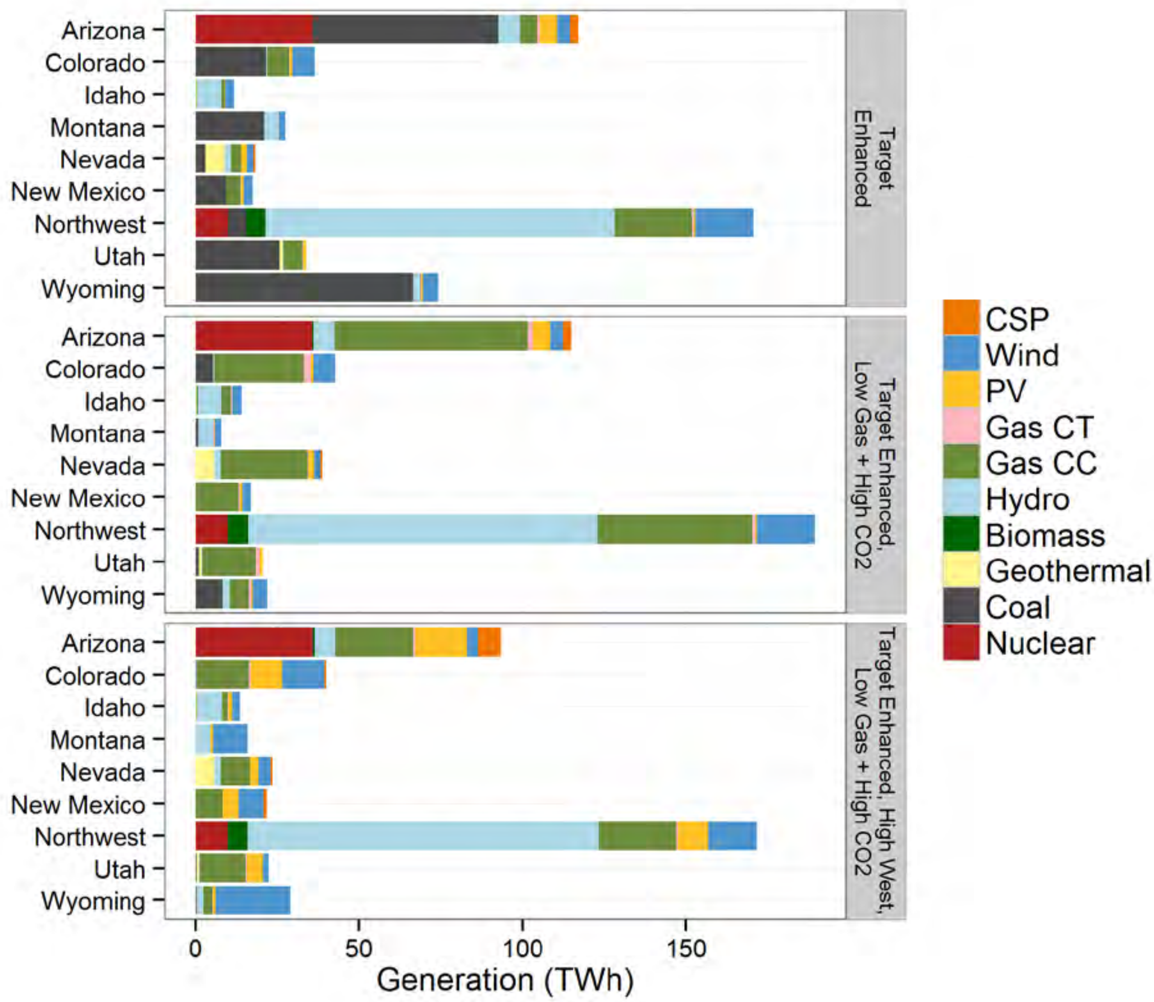


Figure 20. Generation breakdown for other western states in three cases. This graph does not include California or out-of-state California renewable generation.

4.3 Conclusions

This study was an operational analysis of 23 scenarios analyzing the impacts of a low-carbon grid in California that achieves a 50% emissions reduction below 2012 levels. The study focused on understanding the impacts of key assumptions on production costs, curtailment, imports, gas-fleet usage, and other key variables. A wide variety of assumptions were tested, including comparing enhanced and conventional grid flexibility assumptions. The conventional grid flexibility assumptions require 1) importing 70% of out-of-state zero-carbon resources, 2) 25% local minimum generation requirements from natural gas and hydro, 3) no new storage beyond CPUC mandate, and 4) limitations on ancillary service provision from hydro and storage. Although each of these assumptions is independent, it is useful to combine them because the impacts of the suite of assumptions are larger than the sum of the impacts of the individual assumptions. Many likely future enhancements to system flexibility are already considered within the "conventional flexibility" assumptions (see Section 3 and Table 5). In addition, the suite of such "enhanced flexibility" measures is not a set of specific policy proposals but a proxy set of modeling assumptions.

Some of the key findings from this work include:

- California can achieve a 50% reduction in CO_2 levels by 2030 in the electric sector under a wide variety of scenarios and assumptions. The only scenario that did not achieve a 50% reduction had conventional grid flexibility and dry hydro assumptions.

- Conventional grid flexibility assumptions combined with a less diverse portfolio (Target High Solar) led to 14% more carbon emissions than the enhanced grid flexibility assumptions with a more diverse portfolio (Target). Assessing the full cost of achieving enhanced grid flexibility (e.g., synchronous condensers to eliminate the need for local generation requirements) is challenging and should be the subject of future work.

- The energy efficiency and renewable energy additions reduce variable production costs by $4.85 billion in the model with enhanced flexibility. The conventional grid flexibility assumptions increase production costs by $65 million in the Baseline and $550 million in the Target scenario. The model shows the cost reduction of enhanced flexibility is much higher in scenarios with high penetration of renewables. These costs include only the operational costs, not any capital costs associated with the renewables or potential costs that are needed to relax the flexibility constraints (e.g., synchronous condensers for reliability). See Marcus (2015) for more detail on capital costs of these scenarios.

- Curtailment could vary from less than 1% with a diverse portfolio (Target) and enhanced flexibility assumptions to 10% with a less diverse portfolio (Target High Solar) and conventional flexibility assumption.

- The addition of a single flexibility challenge (e.g., the 70% out-of-state import requirement) does not usually have a major impact on production cost or curtailment, but combining several flexibility challenges can have more significant impacts. For example, the combination of an out-of-state import requirement (the 70% rule) and a local minimum generation requirement (25% in California balancing authorities) can lead to challenges because curtailment is often necessary with these significant levels of local fossil-fueled generation and imports.

- Our modeling suggests that a rule requiring physical delivery of out-of-state resources into California (such as a policy limiting unbundled RECs) will increase curtailment and costs.

- A less diverse portfolio (Target High Solar) could create similar carbon reductions and curtailment to a more diverse portfolio (Target) if the rest of the grid is more flexible.

- In the portfolios modeled, imports from fossil-fuel generation are reduced from today's levels by in-state generation in the Baseline scenario due to out-of-state coal retirements and in-state PV generation. Imports from out-of-state renewable generation in the Target scenarios replace imports from fossil-fuel generation in the Baseline scenario. This conclusion is primarily based on the renewable portfolios used in the modeling.

- Achieving higher penetrations in the rest of the western United States (e.g., due to federal or state policies) will have impacts in those states, but does not change the main conclusions of this study for California under assumed levels of grid flexibility. If other regions of the Western Interconnection will not accept imports from California-entitled resources, that could make it more challenging for California to achieve high levels of grid flexibility. The model assumed least-cost dispatch throughout the west to estimate the desirability of sending power from California-entitled resources to other states.
- Flexibility is provided by a variety of technologies during difficult operating periods. Storage and demand response could help reduce operational costs and curtailment in scenarios where institutional flexibility is constrained. Although the enhanced operational flexibility options tend to increase cycling at California gas generators, storage and demand response can help reduce emissions and curtailment while reducing cycling.

The key conclusion of the operational analysis is that achieving a low-carbon grid (with emissions 50% below 2012 levels) is possible by 2030 with relatively limited curtailment (less than 1%) if institutional frameworks are flexible. Less flexible institutional frameworks and a less diverse generation portfolio could lead to higher curtailment (up to 10%), operational costs (up to $800 million higher), and carbon emissions (up to 14% higher).

Future work is important to understand several key questions in more detail, including:

- Friction that exists between balancing authorities is represented by hurdle rates in the model. In reality, bilateral contracts, strategic bidding and offer behavior, and other institutional constraints can cause out-of-merit-order dispatch. How much do these constraints impact the key results of this study?

- The importance of a local minimum generation rule from fossil-fueled sources for maintaining reliability in 2030 is uncertain. Other technologies (e.g., synchronous condensers, synthetic inertia from wind) could be used to provide these reliability services. What is the optimal mix of these services and fossil-fueled generation to provide reliable grid operations in a cost-effective manner for a low-carbon grid? The GE report on dynamics (Miller 2015) addresses some of these questions but does not perform a complete analysis of these scenarios.

- The LCGS scenarios model lower revenues and capacity factors for California gas generators. This could pose a problem for these generators to recover fixed costs as revenues go down significantly. Should there be additional incentives to keep these generators in the market?

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