Investigating a Higher Renewables Portfolio Standard in California

Executive Summary

January 2014

Energy+Environmental Economics

Investigating a Higher Renewables Portfolio Standard in California Executive Summary

January 2014

Energy and Environmental Economics, Inc.
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
415.391.5100
www.ethree.com

Table of Contents

List of Figures

List of Tables

Study Sponsors

Los Angeles Department of Water and Power (LADWP)

Pacific Gas and Electric Company (PG&E)

Sacramento Municipal Utilities District (SMUD)

San Diego Gas & Electric Company (SDG&E)

Southern California Edison Company (SCE)

Advisory Panel

A four-member independent advisory panel provided input and feedback on the study development and results. The members of the advisory panel include:

Dr. Dan Arvizu – Director and Chief Executive of the National Renewable Energy Laboratory (NREL), Golden, CO

Dr. Severin Borenstein – Director of the University of California Energy Institute and Co-Director of the Energy Institute at Haas School of Business, UC Berkeley

Dr. Susan Tierney – Managing Principal at Analysis Group Inc., Boston, MA

Mr. Stephen Wright – Retired Administrator, Bonneville Power Administration; General Manager, Chelan County Public Utility District

Study Team

Energy and Environmental Economics, Inc. (E3)

ECCO International

DNV KEMA

Disclaimer

The study was conducted by Energy and Environmental Economics, Inc. (E3), with assistance from ECCO International and DNV KEMA. The study was funded by LADWP, PG&E, SMUD, SDG&E, and SCE (the utilities). A review committee consisting of utility and California Independent System Operator (CAISO) personnel provided technical input on methodology, data and assumptions. The utilities, the CAISO and Advisory Panel members reviewed and commented on assumptions, preliminary results, and earlier drafts of this report.

E3 and the consulting team thank the utilities, the CAISO and the Advisory Panel members for their invaluable input throughout the process of conducting this analysis. However, all decisions regarding the analysis were made by E3, ECCO International and DNV KEMA. E3, ECCO International and DNV KEMA are solely responsible for the contents of this report, and for the data, assumptions, methodologies, and results described herein.

Executive Summary

This report presents the results of a study of a 50% renewables portfolio standard (RPS) in California in 2030. The study was funded by the Los Angeles Department of Water and Power (LADWP), Pacific Gas and Electric Company (PG&E), the Sacramento Municipal Utilities District (SMUD), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE), ("the utilities") to examine the operational challenges and potential consequences of meeting a higher RPS. This study was conducted by Energy and Environmental Economics (E3), with assistance from ECCO International. A companion study was conducted by DMV KEMA examining "smart grid" technologies that may become available to help alleviate challenges associated with high penetration of distributed generation. An independent advisory panel of experts from industry, government and academia was commissioned to review the reasonableness of the assumptions and to provide input on the study. The California Independent System Operator (CAISO) also provided input on key study assumptions.

The utilities asked E3 to study the following questions:

1. What are the **operational challenges** of integrating sufficient renewable resources to achieve a 50% RPS in California in 2030?

2. What **potential solutions** are available to facilitate integration of variable renewable resources under a 50% RPS?

3. What are the **costs and greenhouse gas impacts** of achieving a 40% or 50% RPS by 2030 in California?

4. **Would an RPS portfolio with significant quantities of distributed renewable generation be lower-cost** than a portfolio of large-scale generation that requires substantial investments in new transmission capacity?

5. What are some **"least regrets" steps** that should be taken prior to—or in tandem with—adopting a higher RPS?

6. What **remaining key issues must be better understood** to facilitate integration of high penetration of renewable energy?

This report describes the analysis that E3 undertook to answer these questions. E3 studied four scenarios, each of which meets California's incremental RPS[1] needs between 33% and 50% RPS in different ways:

+ **Large Solar Scenario** meets a 50% RPS in 2030 by relying mostly on large, utility-scale solar PV resources, in keeping with current procurement trends.

[1] This study assumes that a 50% RPS is defined in the same way as California's current 33% RPS. The standard requires generation from eligible renewable resources to be equal to or exceed 50% of retail sales. Large hydroelectric resources do not count as eligible renewable resources.

- **Small Solar Scenario** meets a 50% RPS by 2030 by relying mostly on larger, distributed (1 – 20 MW) ground-mounted solar PV systems. This scenario also includes some new larger wind and solar.
- **Rooftop Solar Scenario** meets a 50% RPS by 2030 relying in large part on distributed residential and commercial rooftop solar PV installations, priced at the cost of installing and maintaining the systems. This scenario also includes some new larger wind and solar.[2]
- **Diverse Scenario** meets a 50% RPS in 2030 by relying on a diverse portfolio of large, utility-scale resources, including some solar thermal with energy storage and some out-of-state wind.

In addition, the study analyzes two scenarios that serve as reference points against which to compare the costs and operational challenges of the 50% scenarios:

- **33% RPS Scenario** meets a 33% RPS in 2030, representing an extension of the resource portfolio that is already expected to be operational to meet the state's current 33% RPS in 2020.
- **40% RPS Scenario** meets a 40% RPS in 2030 by relying mostly on large, utility-scale solar PV resources.

The geographic scope of the analysis is a combination of the CAISO, LADWP and the Balancing Area of Northern California (BANC) Balancing Authority Areas. All scenarios assume that significant investments and upgrades to both the

[2] In this scenario, new rooftop PV systems beyond the current net energy metering cap are assumed to count as a renewable generation source towards meeting the state's RPS. System owners are assumed to be compensated at the cost of installing and maintaining the systems (i.e. rooftop PV is priced at cost in the revenue requirement calculation). No incentives for solar are assumed, nor does the analysis consider any transfers that could occur if system owners were compensated through other mechanisms, e.g., through net energy metering.

California electrical grid and the state's fleet of thermal generators occur between 2013 and 2030, including the development of a newer, more flexible fleet of thermal generation. Thus, the results of the 33% RPS Scenario are not necessarily indicative of the challenges of meeting a 33% RPS in 2020. Moreover, if these investments are not realized, the operational challenges and costs of meeting a higher RPS in 2030 might look very different than what is shown here.

Table 1 shows the mix of renewable resources modeled for each of the scenarios described above. In addition to the renewable resources added to meet the RPS target, the study assumes that a total of 7,000 MW of behind-the-meter solar photovoltaic resources are installed by 2030 under California's net energy metering (NEM) policies, enough to meet approximately 5% of total load. These resources are assumed to reduce retail sales, but they do not count toward meeting the 2030 RPS.

Table 1: 2030 Renewable generation by resource type and scenario (in GWh)

	33% RPS	40% RPS	50% RPS Large Solar	50% RPS Diverse	50% RPS Small Solar	50% RPS Rooftop Solar
Utility RPS Procurement						
Biogas	2,133	2,133	2,133	4,422	2,133	2,133
Biomass	7,465	7,465	7,465	9,754	7,465	7,465
Geothermal	16,231	16,231	16,231	20,811	16,231	16,231
Hydro	4,525	4,525	4,525	4,525	4,525	4,525
Solar PV - Rooftop	0	943	2,290	2,290	2,290	22,898
Solar PV - Small	6,536	9,365	13,405	13,405	31,724	11,116
Solar PV - Large	22,190	33,504	49,667	29,059	31,349	31,349
Solar Thermal	4,044	4,044	4,044	10,913	4,044	4,044
Wind (In State)	20,789	24,561	29,948	27,659	29,948	29,948
Wind (Out-of-State)	4,985	4,985	4,985	11,854	4,985	4,985
Subtotal, Utility Gen	**88,897**	**107,755**	**134,693**	**134,693**	**134,693**	**134,693**
Customer Renewable Generation						
Solar PV – Rooftop, net energy metered	10,467	10,467	10,467	10,467	10,467	10,467
Subtotal, Customer Gen	**10,467**	**10,467**	**10,467**	**10,467**	**10,467**	**10,467**
Total Renewable Generation						
Total, All Sources	**99,365**	**118,222**	**145,160**	**145,160**	**145,160**	**145,160**

The study is the first comprehensive effort to assess the technical challenges of operating the California system at a 50% RPS with high penetration of both wind and solar energy. This study examines scenarios for California with up to 15% of electric load served by wind energy, and 28% served by solar energy. This is a much higher penetration of wind and solar energy than has ever been achieved anywhere in the world. In Germany, widely known as a world leader in renewable energy deployment, 21.9% of electricity generation was renewable in

2012, including 7.4% wind and 4.5% solar.[3] In Spain, renewable energy represented 24% of total generation in 2012, including 18% wind and 4% solar.[4] Wind served 30% of domestic load in Denmark in 2012[5]; however, Denmark is a very small system with strong interconnections to the large European grid, and it frequently sells excess wind energy to its neighbors. Other jurisdictions such as Norway, New Zealand and British Columbia have served over 90% of electric load with renewables by counting large hydroelectric resources; these resources do not count toward California's RPS.

At the same time, numerous studies have pointed to the need to decarbonize the electric sector as a key strategy for achieving deep, economy-wide reductions in greenhouse gas emissions as well as energy security and economic development benefits.[6] To that end, many other jurisdictions have set high renewables goals. The European Union Renewables Directive mandates that at least 20% of total energy consumption (including transportation, industrial and other non-electric fuel uses) come from renewable energy sources by 2020. By 2030, Germany plans to generate 50% of its electricity supply with renewable sources, including large hydro.[7] Finland aims to achieve 38% of final energy consumption (including transportation, etc.) from renewable energy sources by

[3] "Gross electricity generation in Germany from 1990 to 2012 by energy source," Accessed July 2013. <**www.ag-energiebilanzen.de/componenten/download.php?filedata=1357206124.pdf&filename=BRD_Stromerzeugung1990_2012.pdf&mimetype=application/pdf**>
[4] "Statistical series of the Spanish Electricity System," Red Electrica, 2013, Accessed August 2013. <**http://www.ree.es/ingles/sistema_electrico/series_estadisticas.asp** >
[5] "Monthly Statistics: Electricity Supply," Danish Energy Agency, Accessed: August 2013. < **http://www.ens.dk/info/tal-kort/statistik-nogletal/manedsstatistik**>
[6] See **http://www.ipcc.ch/pdf/assessment-report/ar4/syr/ar4_syr.pdf,** **http://www.iea.org/techno/etp/etp10/English.pdf**, and **http://www.ethree.com/publications/index_2010.php**.
[7] "Energy Policies of IEA Countries – Germany," International Energy Agency, 2013 **http://www.iea.org/w/bookshop/add.aspx?id=448**

2020 by relying in large part on biomass resources.[8] While no country has served 40 or 50 percent of its load with variable wind and solar resources, California is not alone in considering potential futures with high renewables. This study represents an important advancement in understanding the impacts of achieving a high RPS.

This report is organized as follows. The remainder of this section summarizes the study's key findings in response to the six questions posed above. Section 2 describes the analytical approach and key inputs to the study. Section 3 describes the analysis of operational challenges associated with a 50% RPS. Section 4 introduces a number of potential solutions that may provide lower-cost ways of integrating renewable resources into the grid. Section 5 presents the cost and greenhouse gas impacts of achieving a 50% RPS. Section 6 concludes by discussing the results and summarizing the research needs identified in this study. A series of technical appendices provide details about the analysis that was conducted.

OPERATIONAL CHALLENGES OF ACHIEVING A 50% RPS

The study utilizes E3's Renewable Energy Flexibility (REFLEX) Model on ECCO's ProMaxLT production simulation platform to investigate the operational and flexibility requirements associated with a 50% RPS. REFLEX is specifically designed to investigate renewable integration issues.[9] REFLEX performs random

[8] "Energy Policies of IEA Countries – Finland," International Energy Agency, 2013, http://www.iea.org/Textbase/npsum/finland2013SUM.pdf

[9] Throughout this report, the term "renewable integration" is used to encompass a range of operational challenges encountered under higher renewable energy penetrations including "overgeneration" of resources,

draws of weather-correlated load, wind, solar and hydro conditions taken from a very large sample of historical and simulated data. REFLEX thus considers operational needs associated with high and low load conditions, high and low hydro conditions, and a range of wind and solar conditions, as well as a broad distribution of the hourly and sub-hourly operating reserve requirements.

REFLEX runs are presented for four scenarios: (1) the 33% RPS Scenario, (2) the 40% RPS Scenario, (3) the 50% RPS Large Solar Scenario, and (4) the 50% RPS Diverse Scenario.[10] Additional runs are presented for variations of the 50% RPS Large Solar Scenario which include the implementation of several potential renewable integration solutions. This analysis does not attempt to find an optimal generation mix or set of renewable integration solutions under the 50% RPS scenarios. Rather, the analysis explores the operational challenges of a 50% RPS and provides directional information about the potential benefits and cost savings of the renewable integration solutions.

The largest integration challenge that emerges from the REFLEX runs is “overgeneration”. Overgeneration occurs when “must-run” generation—non-dispatchable renewables, combined-heat-and-power (CHP), nuclear generation, run-of-river hydro and thermal generation that is needed for grid stability—is greater than loads plus exports. This study finds that overgeneration is pervasive at RPS levels above 33%, particularly when the renewable portfolio is

---

whereby electricity supply exceeds demand net of exports, as well as the fuel costs associated with ramping fossil generation to meet load net of renewable generation.

[10] REFLEX runs were not conducted for the Small Solar and Rooftop Solar Scenarios. The integration challenges for these scenarios are very similar to those of the Large Solar Scenario; therefore the Large Solar Scenario is used as a proxy for all three high solar scenarios.

dominated by solar resources. This occurs even after thermal generation is reduced to the minimum levels necessary to maintain reliable operations.

Figure 1 shows an April day in 2030 under the 33% RPS, 40% RPS, and the 50% RPS Large Solar Scenarios on which the system experiences both low load conditions and high solar output. A very small amount of overgeneration is observed at 33% RPS. The 40% RPS Scenario experiences over 5,000 MW of overgeneration, while the 50% RPS Large Solar Scenario experiences over 20,000 MW of overgeneration.

Table 2 shows overgeneration statistics for the 33%, 40% and 50% RPS Large Solar Scenarios. In the 33% RPS scenario, overgeneration occurs during 1.6% of all hours, amounting to 0.2% of available RPS energy.[11] In the 50% RPS Large Solar case, overgeneration must be mitigated in over 20% of all hours, amounting to 9% of available RPS energy, and reaches 25,000 MW in the highest hour. Potential solutions or portfolios of solutions must therefore be available during large portions of the year and must comprise a large total capacity.

This study assumes that managed curtailment of renewable generation occurs whenever total generation exceeds total demand plus export capability. This is critical to avoid too much energy flowing onto the grid and causing potentially serious reliability issues. As long as renewable resource output can be curtailed in the manner assumed here, the study does not find that high penetration of wind and solar energy results in loss of load. Renewable curtailment is

[11] Curtailment as a percentage of available RPS energy is calculated as: overgeneration divided by the amount of renewable energy that is needed to meet a given RPS target.

therefore treated as the “default” solution to maintain reliable operations. However, the study also evaluates additional solutions that would reduce the quantity of renewable curtailment that is required.

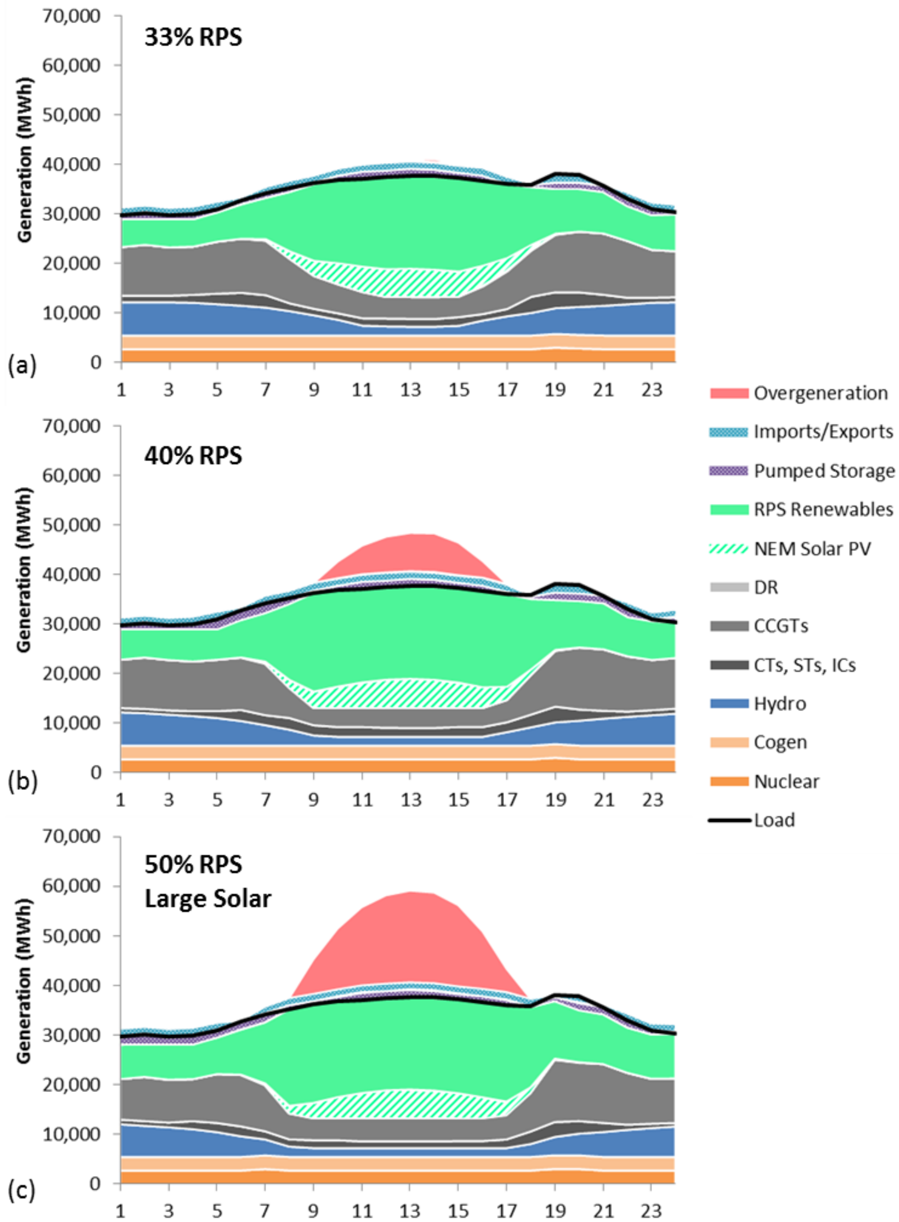


Figure 1: Generation mix calculated for an April day in 2030 with the (a) 33% RPS, (b) 40% RPS, and (c) 50% RPS Large Solar portfolios showing overgeneration

Table 2: 2030 Overgeneration statistics for the 33%, 40% and 50% RPS Large Solar Scenarios

Overgeneration Statistics	33% RPS	40% RPS	50% RPS Large Solar
Total Overgeneration			
GWh/yr.	190	2,000	12,000
% of available RPS energy	0.2%	1.8%	8.9%
Overgeneration frequency			
Hours/yr.	140	750	2,000
Percent of hours	1.6%	8.6%	23%
Extreme Overgeneration Events			
99th Percentile (MW)	610	5,600	15,000
Maximum Observed (MW)	6,300	14,000	25,000

REFLEX also tests for shortages in "ramping" capability – the ability of the generation fleet to accommodate large changes in the net load served over one or more hours.[12] While the scenarios evaluated in this study show no instances of a shortage of ramping capability that would create reliability problems, this result is driven partly by the assumption that renewable curtailment can be utilized not just to avoid overgeneration, but also as a tool to manage net load ramps. In order to ensure reliable operations, REFLEX utilizes "prospective" curtailment, in which the system operator looks ahead one or more hours, subject to uncertainty and forecast error, and curtails renewable output in order to smooth out hourly and multi-hour ramps. This occurs in instances where this system would otherwise be unable to accommodate the steep upward ramps from the mid-afternoon "trough" in net load to the evening peak. Planned and

[12] Net load is defined as load minus renewable generation.

carefully-managed curtailment is therefore a critical tool that is used in the modeling to maintain reliable operations in the face of overgeneration and ramping challenges caused by the higher RPS.

The quantity of managed renewable energy curtailment increases exponentially for RPS requirements that move from 40% to 50% RPS. For example, while the *average* curtailed RPS energy for the 50% RPS Large Solar Scenario is 9%, the *marginal* curtailment—the proportion of the next MWh of renewable resources added to the portfolio that must be curtailed—is significantly higher: 22-25% for most renewable resources and 65% for solar PV, as seen in Table 3. Curtailment amounts to 26% of the RPS energy required to move from a 33% to 50% RPS under the Large Solar Scenario.

Table 3: Marginal overgeneration (% of incremental MWh resulting in overgeneration) by technology for various 2030 RPS scenarios

Technology	33% RPS	40% RPS	50% RPS Large Solar	50% RPS Diverse
Biomass	2%	9%	23%	15%
Geothermal	2%	9%	23%	15%
Hydro	2%	10%	25%	16%
Solar PV	5%	26%	65%	42%
Wind	2%	10%	22%	15%

POTENTIAL INTEGRATION SOLUTIONS

Implementation of one or more renewable integration solutions may reduce the cost of achieving a 50% RPS relative to the default renewable curtailment solution. This study considers the following potential solutions: (1) Enhanced Regional Coordination; (2) Conventional Demand Response; (3) Advanced

Demand Response; (4) Energy Storage; and, (5) 50% RPS with a more diverse renewable resource portfolio (the Diverse Scenario). The most valuable integration solutions are those that can reduce solar-driven overgeneration during daylight hours when the system experiences low load conditions. Downward flexibility solutions, including increased exports, flexible loads, and diurnal energy storage help to mitigate this overgeneration. Alternatively, procurement of a more diverse portfolio of renewable resources, which includes less solar and disperses the renewable generation over more hours of the day, reduces the daytime overgeneration compared to the Large Solar portfolio.

The study evaluates changes in the renewable integration challenges associated with the 50% RPS Large Solar Scenario from sequentially implementing potential integration solutions sized at 5,000 MW. The study therefore evaluates the directional impact of the solution, but does not attempt to identify an optimal or least-cost set of solutions. Table 4 shows the overgeneration statistics for the Large Solar Scenario and each of the solutions tested. With only the renewable curtailment solution implemented, overgeneration is approximately equal to 9% of the available renewable energy. Integration solutions that provide only upward flexibility, like conventional demand response, do not significantly decrease this overgeneration. However, integration solutions that provide 5,000 MW of downward flexibility, such as energy storage, reduce the overgeneration to between 3% and 4% of the available renewable energy.

Similarly, the diverse portfolio of renewable resources evaluated here reduces overgeneration to approximately 4% of the available renewable energy.[13]

This study assesses each of the solutions in isolation, with the aim of indicating promising directions for further investigation. However, preliminary analysis suggests that the effects of the various solutions, if implemented together, are complementary. Because overgeneration increases exponentially at RPS levels approaching 50%, optimization of the renewable portfolio with a combination of solutions could substantially reduce the quantity of curtailment required to meet a 50% RPS. However, avoiding all instances of renewable curtailment may be cost-prohibitive.

[13] This study considers a diverse portfolio consisting of specific quantities of in-state wind, out-of-state wind, solar thermal with energy storage, and other technologies. A different renewable generation mix would result in a different quantity of overgeneration.

Table 4: 2030 overgeneration statistics for 50% RPS Large Solar Scenario and four solution cases

Overgeneration Statistics	50% RPS Large Solar	Enhanced Regional Coordination	Conventional Demand Response	Advanced DR or Energy Storage	Diverse Portfolio
Total Overgeneration					
GWh/yr.	12,000	4,700	12,000	5,000	5,400
% of available RPS energy	8.9%	3.4%	8.8%	3.7%	4.0%
Overgeneration					
Hours/yr.	2,000	1,000	2,000	1,200	1,300
Percent of hours	23%	12%	23%	14%	15%
Extreme Overgeneration Events					
99th Percentile (MW)	15,000	9,900	15,000	9,900	10,000
Maximum Observed (MW)	25,000	20,000	25,000	20,000	19,000

The solution quantities evaluated in these cases are informed by the size of the overgeneration caused by a 50% RPS, and not by any estimate of the feasibility or technical potential to achieve each solution. For example, we are not aware of any detailed studies of the technical potential for pumped storage or upwardly-flexible loads in California. Battery technologies have not been fully demonstrated as commercial systems in the types of applications or at the scale required to address the integration issues identified in this study. Regional coordination is promising but has progressed slowly over the past decade. There are likely to be significant challenges to implementing any of these solutions.

COST AND RATE IMPACTS

This study calculates the statewide total cost and average retail rate for each of the 50% RPS scenarios. The 33% and 40% RPS scenarios are shown as a reference point. The total cost includes the cost of procuring and operating the renewable and thermal resources considered in this study, the cost of transmission and distribution system investments needed to deliver the renewable energy to loads, and non-study-related costs such as the cost of the existing grid. The costs do not include real-time grid operating requirements such as maintaining frequency response. The total cost for the study area is divided by projected retail sales to calculate an average, ¢/kWh rate across all customer classes.

As a backdrop, the study estimates that the average retail rate in California could increase from 14.4 ¢/kWh in 2012 to 21.1 ¢/kWh in 2030 (in 2012 dollars), a 47% increase, before higher levels of RPS beyond the current 33% statute are taken into consideration. [14] This increase is driven largely by trends outside the scope of this study, such as the need to replace aging infrastructure, rather than by RPS policies. Other analysis has estimated that compliance with the current 33% RPS is expected to raise investor owned utility rates by 6-8% between 2011 and 2030; the approximately 40% remaining rate impact expected over this period would be attributable to other factors.[15]

---

[14] Throughout the study, all costs are presented in 2012 real dollars unless otherwise noted.

[15] This estimate is derived from analysis developed by E3 in the Long-Term Procurement Plan (LTPP) proceeding http://www.cpuc.ca.gov/NR/rdonlyres/070BF372-82B0-4E2B-90B6-0B7BF85D20E6/0/JointIOULTPP_TrackI_JointIOUTestimony.pdf

Achieving a 40% RPS could lead to an additional increase of 0.7 ¢/kWh, or 3.2%, over the 33% RPS Scenario under base case assumptions regarding the price of natural gas, CO_2 emissions allowances and renewable energy resources. A 50% RPS would increase rates by 9 – 23% relative to a 33% RPS under base case assumptions.

Figure 2, Table 5 and Table 6 below show the average rate increase of each of the five RPS scenarios compared to the 33% portfolio in 2030. The analysis reveals several interesting findings:

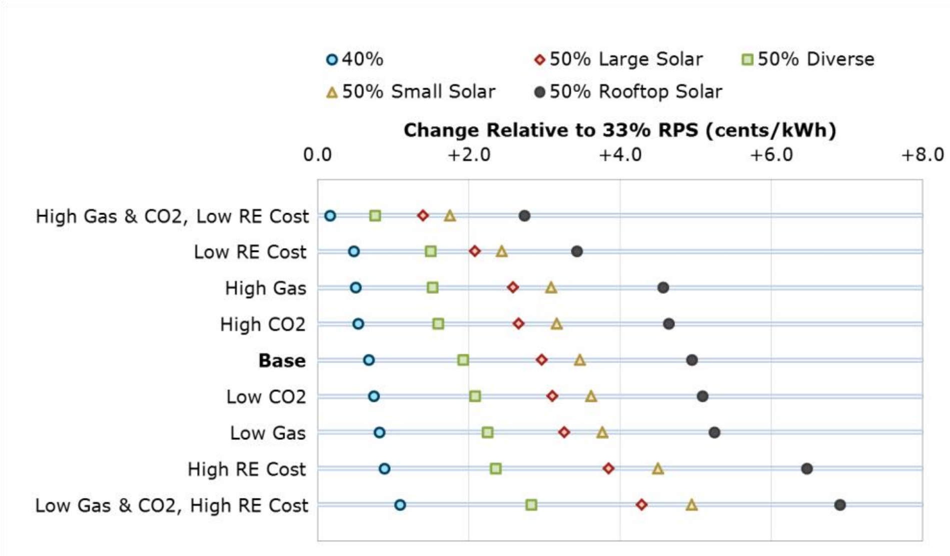
1. Under a wide range of CO_2, natural gas and renewable energy prices (gas prices from $3-10/MMBtu, CO_2 prices from $10-100/metric ton, and a range of solar PV and wind costs) the higher RPS Scenarios result in an increase in average electric rates. The rate impacts are expected to be lowest under the high gas & CO_2 price sensitivity with low renewable energy costs.

2. Rate increases are expected to be significantly higher under the 50% RPS Scenarios than under the 40% RPS Scenario. This is primarily due to the exponential increase in renewable curtailment as the RPS target increases towards 50%, requiring a significant “overbuild” of the renewable portfolio to meet the RPS target.

3. The Diverse Scenario shows a substantially lower rate impact than the more heavily solar dominated cases, primarily because the diverse portfolio results in less overgeneration.

4. The rank order on costs between the Scenarios stays the same under all uncertainty ranges considered. Costs are expected to be highest under the

Rooftop Solar Scenario, followed by the Small Solar, Large Solar and Diverse Scenarios. The cost differences between these sensitivity results are reduced when assuming lower solar PV costs than in the base case.



Note: RE = renewable energy

Figure 2: Cost differences between RPS portfolios under a range of assumptions; relative to 2030 33% RPS scenario (2012 cents/kWh)

Table 5: Average electric rates for each Scenario under a range of input assumptions (2012 cents/kWh)

	33% RPS	40% RPS	50% RPS Large Solar	50% RPS Diverse	50% RPS Small Solar	50% RPS Rooftop Solar
Average System Rate (2012 cents/kWh)						
Base	21.1	21.8	24.1	23.1	24.6	26.1
Low Gas	19.8	20.6	23.0	22.0	23.5	25.0
High Gas	22.9	23.4	25.5	24.4	26.0	27.5
Low CO_2	20.5	21.2	23.6	22.5	24.1	25.6
High CO_2	22.6	23.1	25.2	24.2	25.7	27.2
Low RE Cost	21.0	21.5	23.1	22.5	23.5	24.5
High RE Cost	21.2	22.1	25.1	23.6	25.7	27.7
Low Gas & CO_2, High RE Cost	19.2	20.3	23.5	22.0	24.1	26.1
High Gas & CO_2, Low RE Cost	24.2	24.4	25.6	25.0	26.0	27.0

Table 6. Percent change in average electric rates of each Scenario relative to 33% RPS Scenario, under a range of input assumptions (% change in 2012 $)

	33% RPS	40% RPS	50% RPS Large Solar	50% RPS Diverse	50% RPS Small Solar	50% RPS Rooftop Solar
Percentage Change in Average System Rate (relative to 33% RPS)						
Base	n/a	3.2%	14.0%	9.1%	16.4%	23.4%
Low Gas	n/a	4.1%	16.5%	11.3%	19.1%	26.5%
High Gas	n/a	2.2%	11.3%	6.6%	13.5%	19.9%
Low CO_2	n/a	3.6%	15.2%	10.2%	17.7%	24.9%
High CO_2	n/a	2.4%	11.8%	7.1%	14.0%	20.6%
Low RE Cost	n/a	2.3%	9.9%	7.1%	11.6%	16.3%
High RE Cost	n/a	4.2%	18.1%	11.1%	21.2%	30.5%
Low Gas & CO_2, High RE Cost	n/a	5.7%	22.3%	14.7%	25.8%	36.0%
High Gas & CO_2, Low RE Cost	n/a	0.7%	5.8%	3.1%	7.2%	11.3%

The projected cost increases for the higher RPS scenarios are due largely to the high and increasing cost of renewable integration. While wind and solar costs are projected to be comparable to the cost of conventional resources on a levelized cost of energy (LCOE) basis in 2030, overgeneration and other integration challenges have a substantial impact of the total costs for the 50% RPS scenarios. Moreover, renewable generation is shown to have very little resource adequacy benefits beyond 33% RPS due to increased saturation of the grid with solar energy (see section 2.3 of the full report).

Table 7: 2030 revenue requirement (2012 $ billion) for each Scenario, percentage change is relative to 33% RPS

Revenue Requirement Category	33% RPS	40% RPS	50% RPS Large Solar	50% RPS Diverse	50% RPS Small Solar	50% RPS Rooftop Solar
CO_2 Compliance Cost	3.2	2.9	2.5	2.4	2.5	2.5
Conventional Generation	20.3	19.5	18.7	18.1	18.7	18.6
Renewable Generation	8.2	10.6	17.1	14.8	18.5	22.8
Transmission	6.5	7.1	7.8	7.9	7.4	7.3
Distribution	16.2	16.2	16.3	16.3	16.7	16.5
Misc/Other Costs	2.5	2.5	2.5	2.5	2.5	2.5
Total	**56.9**	**58.8**	**64.9**	**62.1**	**66.3**	**70.3**
Percentage Change	n/a	3.2%	14.0%	9.1%	16.4%	23.4%

The total cost of each scenario, in terms of annual revenue requirement in 2030, is shown in Table 7, while the cumulative capital investment through 2030, incremental to meeting a 33% RPS in 2020, for each scenario is shown in Table 8.

Table 8: Cumulative capital investment through 2030, incremental to 33% RPS in 2020, by scenario (2012 $ billion)

	33% RPS	40% RPS	50% RPS Large Solar	50% RPS Diverse	50% RPS Small solar	50% RPS Rooftop Solar
New Renewable Generation	9.2	29.5	65.2	61.0	72.0	105.3
New Conventional Generation	11.7	11.2	11.2	11.2	11.2	11.2
New Transmission	2.8	6.6	12.0	15.2	9.3	8.5
New Distribution	0.6	0.9	1.4	1.4	4.2	3.0
Total Capital Investment	**24.4**	**48.1**	**89.8**	**88.7**	**96.6**	**128.0**

The total increase in annual revenue requirement associated with a 50% RPS in 2030 ranges from $5.2 to $13.3 billion above the 33% RPS scenario; this includes CO_2, fuel and capacity savings in the conventional generation cost category, as well as increases in renewable procurement costs. The cumulative capital investment in the 50% RPS Scenario ranges from $64.4 to $103.7 billion above the 33% RPS scenario, in real 2012 dollars under base case assumptions, before the implementation of the additional renewable integration solutions that are investigated in this study.

EFFECT OF RENEWABLE INTEGRATION SOLUTIONS

The cost impacts shown in the tables above incorporate only the "default" integration solution of renewable energy curtailment. Implementation of one or more alternative solutions may reduce the cost impacts by enabling a larger proportion of renewable energy output to be delivered to the grid.

A detailed cost-benefit analysis of these renewable integration solutions is beyond the scope of this study. In lieu of such an analysis, we provide cost and rate results under an illustrative range of high and low cost assumptions for the implementation of 5,000 MW of each of the solutions that are shown to have a potential renewable integration benefit. Even though the study assumes significant quantities of each solution (5,000 MW) are implemented, these cases are not sufficient to fully eliminate the overgeneration challenge.

As noted above, the study does not include an analysis of the optimal level of integration solutions, nor does it assess the feasibility of procuring or implementing 5,000 MW of these renewable integration solutions by 2030. The technical potential to achieve various solutions is unknown, and there are likely to be significant technical, regulatory and permitting barriers to implementing solutions at this magnitude.

Table 9 shows the cost ranges assumed for each solution. These assumptions represent, at a high level, a range of potential costs for each category. In reality, each category would likely be made up of a number of individual measures or projects, each of which would have unique costs and benefits. For example, the energy storage solution case could include a mixture of pumped storage and other storage technologies such as compressed air energy storage (CAES) or flow batteries. Nevertheless, this section provides an indication of the extent to which cost reductions might be achieved through implementation of solutions in each of these categories.

Table 9: High and low cost estimates for solution categories modeled in this study (2012 $)

Solution	Sensitivity	Basis	Cost Metric
Storage	Low	Pumped hydro cost ($2,230/kW; 30-yr lifetime); Black and Veatch *Cost and Performance Data for Power Generation Technologies*[16]	$375/kW-yr
	High	Battery cost ($4,300/kW; 15-yr lifetime); Black and Veatch *Cost and Performance Data for Power Generation Technologies*	$787/kW-yr
Flexible Load	Low	Load shift achieved through rate design at no incremental cost	$0/kW-yr
	High	Average TRC cost of thermal energy storage ($2,225/kW; 15-yr lifetime); E3 *Statewide Joint IOU Study of Permanent Load Shifting*[17]	$413/kW-yr
Regional Coordination	Low	Assume CA receives $50/MWh for exported power	-$50/MWh exported
	High	Assume CA pays $50/MWh to export incremental power	$50/MWh exported

Figure 3 shows the effect of implementing these solutions, compared to the 33% RPS Scenario. As a benchmark, the 50% RPS Large Solar Scenario, with only the default renewable curtailment solution, is expected to increase average

[16] Study available at: http://bv.com/docs/reports-studies/nrel-cost-report.pdf.
[17] Study available at: http://www.ethree.com/public_projects/sce1.php.

rates by 3 ¢/kWh, or 14%, relative to the 33% RPS Scenario. The Diverse Scenario is also shown as an integration solution, along with a point estimate of its rate impact under base case assumptions. The Diverse Scenario reduces the average rate by 1 ¢/kWh relative to the Large Solar Scenario.

The Enhanced Regional Coordination and Advanced DR solutions provide cost savings relative to the Large Solar Scenario, even under the "high" cost range. The "low" cost range for energy storage, modeled here as 5,000 MW of relatively low-cost pumped storage, would be expected to reduce the total cost of achieving the 50% RPS Large Solar Scenario by just over 0.5 ¢/kWh.[18] Only the high-cost battery storage case results in higher costs; however, it should be noted that the engineering cost estimates shown here do not include site-specific costs, performance guarantees and other costs that would be incurred during commercial deployment. All of the solution cases modeled here result in higher expected rates compared to the 33% RPS Scenario.

[18] This study does not assess the feasibility of implementing 5,000 MW of pumped storage in the state by 2030.

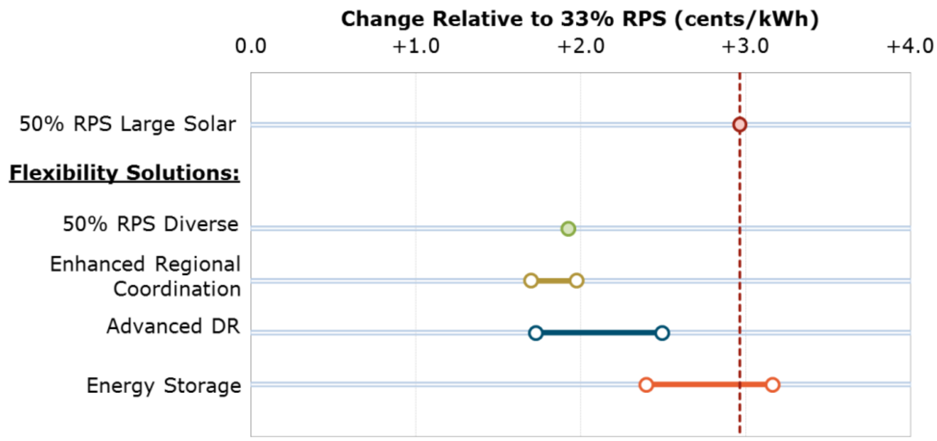


Figure 3: Cost impacts of solution cases (assuming 5,000 MW change) under low and high cost ranges, relative to 2030 33% RPS Scenario (2012 cents/kWh)

GREENHOUSE GAS IMPACTS

The 50% RPS Scenarios reduce greenhouse gas (GHG) emissions relative to the 33% RPS Scenario. Increasing the RPS from 33% to 40% reduces GHG emissions by approximately 6 million metric tons in 2030, while a 50% RPS would reduce GHG emissions by 14-15 million metric tons relative to a 33% RPS in 2030. The implied cost of GHG emissions reductions is calculated as the change in total cost (excluding CO_2 compliance costs) divided by the change in GHG emissions relative to the 33% RPS Scenario.[19] The implied carbon abatement cost is $340/ton for the 40% RPS Scenario, $403/ton for Diverse Scenario, and $637/ton for the Large Solar Scenario, under the default renewable curtailment

[19] This formulation implicitly attributes all of the cost of meeting a higher RPS to GHG emissions reductions. It therefore ignores other potential societal benefits of increased renewable penetration such as reduced emissions of “criteria” pollutants such as NO_x and SO_x.

solution. GHG abatement costs would be reduced if lower-cost, low carbon solutions to the overgeneration challenge can be implemented.

DISTRIBUTED GENERATION IMPACTS

This study considers two scenarios composed largely of distributed solar PV generation (DG PV): a Small Solar and a Rooftop Solar Scenario. DG PV is assessed for its impact on the distribution and transmission systems as well as for the difference in cost and performance relative to larger systems located in sunnier areas. The study relies on the methods used in previous studies for the California Public Utilities Commission (CPUC) to determine both benefits—in the form of reduced system losses and deferred transmission and distribution investments—and costs—in the form of distribution system upgrades needed to accommodate high levels of DG that result in “backflow” from distribution feeders onto the main grid.

The Small Solar and Rooftop Scenarios are found to be costlier than the Large Solar and Diverse Scenarios. This is largely due to the difference in cost and performance assumed for DG PV systems relative to central station systems. Rooftop systems, in particular, are significantly more expensive to install on a per-kW basis than larger systems and have lower capacity factors. Rooftop PV systems tend to have lower capacity factors (partly due to suboptimal tilt and orientation) relative to larger, ground-mounted systems that can utilize tracking technologies. DG PV is found to reduce transmission costs relative to larger systems located in remote areas; however, distribution costs are found to be higher due to the need for significant investments to accommodate very high penetration of PV on the distribution system. It should be noted that this study does not address issues related to retail rate design or net energy metering. The DG PV systems are priced at the cost of installing and maintaining the systems, identical to the treatment of central station PV systems, in the revenue requirement and average rate calculations.

NEXT STEPS

Although the focus of this study is on grid operations with very high renewable penetrations in 2030, there are a number of shorter-term "least-regrets" opportunities that the evidence in this report suggests should be implemented prior to or in parallel with a higher RPS standard. The four "least regrets" opportunities identified in this study include:

1. **Increase regional coordination.** This study shows that increased coordination between California and its neighbors can facilitate the task of integrating more renewable resources into the bulk power system at a lower cost. Although California already depends on its neighbors for imports during summer peak periods, an increased level of coordination across the West would include more sharing of flexible resources to support better integration of the rich endowment of wind energy in the Pacific Northwest and Rocky Mountains and solar resources in the Desert Southwest.
2. **Pursue a diverse portfolio of renewable resources.** The study shows that increasing the diversity of resources in California's renewable energy portfolio has the potential to reduce the need for managed curtailment. More diverse renewable generation profiles can better fit within California's energy demand profile. The benefits of developing a diverse portfolio are complemented by and in many ways tied directly to increased regional coordination, since the largest benefit is likely to be achieved through increased geographic diversity across a wide area.

3. **Implement a long-term, sustainable solution to address overgeneration before the issue becomes more challenging.** A long-term, sustainable implementation and cost-allocation strategy to manage the potential large amounts of overgeneration that could result from a higher RPS should be developed before overgeneration jeopardizes reliability, and before curtailment impacts financing of new renewable generation projects. A long-term, sustainable solution must be technically feasible, economically efficient and implementable in California. It must include a mechanism for ensuring that renewable developers continue to receive a sufficient return to induce investment in projects on behalf of California ratepayers.

4. **Implement distributed generation solutions.** Increased penetration of distributed generation necessitates a more sustainable, cost-based strategy to procure distributed generation. This requires a reexamination of retail rate design and net energy metering policies, as well as implementation of distribution-level solutions and upgrades, including smart inverters with low-voltage ride-through capabilities that allow distributed photovoltaic systems to operate under grid faults.

There are also a number of key areas for future research that are beyond the scope of this study, but are critical to enable the bulk power systems to continue to work reliably and efficiently in the future. These include:

+ **The impact of a combined strategy of multiple renewable integration solutions.** This study finds that grid integration solutions will be critical to achieving a higher RPS at lowest cost. Because each solution has its own specific costs and benefits, a critical next step is to analyze combinations of these potential solutions to help develop a more comprehensive, longer-term grid integration solution to higher RPS.

+ **Research and development for technologies to address overgeneration.** Technology needs to support higher renewable energy penetration and to address the overgeneration challenge include diurnal energy flexibility and efficient uses for surplus solar generation during the middle of the day. Promising technologies include:

  - Solar thermal with energy storage;
  - Pumped storage;
  - Other forms of energy storage including battery storage;
  - Electric vehicle charging;
  - Thermal energy storage; and
  - Flexible loads that can increase energy demand during daylight hours.

+ **Technical potential and implementation of solutions.** This study points to the need for solutions to the renewable integration challenges to be planned and implemented on the same timeline as, or before, higher renewable penetration. However, the technical potential to achieve each solution is unknown at this time. A significant effort is needed to characterize the technical potential, cost, and implementation challenges for pumped storage, battery technologies, upwardly-flexible loads, more diverse renewable resource portfolios, and other potential renewable integration solutions.

+ **Sub-five minute operations.** A better understanding of the sub-five minute operations, including frequency, inertia and regulation needs, under a higher RPS is needed. This is particularly pressing in California where significant changes are planned to the state's existing thermal generation fleet, including the retirement of coastal generators utilizing once-through cooling. Research is needed regarding potential costs and the feasibility and performance of potential solutions, such as synthetic inertia.

- **Size of potential export markets for excess energy from California.** California has historically been an importer of significant quantities of electric energy. Under a 50% RPS, California would have excess energy to sell during many hours of the year. The extent to which electricity providers in other regions might be willing to purchase excess energy from California is unknown. This study assumes that California can export up to 1500 MW of energy during every hour of the year based on a high-level assessment of supply and demand conditions in other regions, and shows that higher levels of exports could significantly reduce the cost of achieving a 50% RPS. Further research might be able to shed additional light on this question.
- **Transmission constraints.** This study does not include an assessment of transmission constraints within California, and how those constraints might impact renewable integration results including reliability, cost and overgeneration. For example, if a large proportion of the solar energy resources modeled in this study are located in Southern California, northbound transmission constraints on Path 15 and Path 26 may result in significantly higher overgeneration than is indicated in this study. Challenges may also be more acute within the BANC and LADWP Balancing Authority Areas, which have limited transfer capability to the CAISO system.
- **Changing profile of daily energy demand.** Daily load shapes are expected to evolve over time, with increases in residential air conditioning and electric vehicle loads. This could shift the peak demand period farther into the evening, potentially exacerbating the overgeneration challenge during daylight hours.[20]

[20] San Diego Gas & Electric and Sacramento Municipal Utility District are already seeing peak demand occur between 5:30 and 6:00 pm on some days.

- **Future business model for thermal generation and market design.** This analysis points toward a fundamental shift in how energy markets are likely to operate under high penetration of renewable energy. Energy markets are unlikely to generate sufficient revenues to maintain the flexible fleet of gas generation that the state will need to integrate high levels of renewable energy. Moreover, there may be a significant number of hours in which market prices are negative. New market products for flexibility, inertia, frequent startups and capacity may be necessary to ensure that the generation fleet maintains the necessary operating characteristics.
- **Optimal thermal generation fleet under high RPS.** Procurement choices will need to be made regarding trade-offs between combined-cycle gas generators, frame and aeroderivative combustion turbines, and other technologies with newly-important characteristics for renewable integration, such as low minimum generation levels and high ramp rates. The flexibility needs of the state's thermal fleet may also interact with local air quality regulations, which limit the number of permitted power plant starts.
- **Natural gas system impacts and supply.** Operating the grid under a higher RPS may require more flexibility in the natural gas delivery system and markets. Whether the natural gas delivery system can support the simultaneous operation of gas-fired generators necessary for renewable integration is an important area for further research.
- **Operational challenges of a 40% RPS.** The study finds that overgeneration occurs at 33% RPS and is significant at 40% RPS, but does not evaluate the impact of renewable integration solutions at a 40% RPS in detail.
- **Cost-effectiveness of a higher RPS relative to other measures for reducing GHG emissions.** This study indicates that a 50% RPS may be a relatively high-cost means of reducing GHG emissions (over $300/ton, as compared

to CO_2 allowance price forecasts of \$30-100/ton). To be sure, there are many other benefits from higher renewable penetration besides GHG reduction. Nevertheless, it would be instructive to compare the cost of a 50% RPS with the cost of reducing GHG emissions in other sectors such as transportation, industry and buildings.

CONCLUSION

This study assesses the operational impacts, challenges, costs, greenhouse gas reductions, and potential solutions associated with a 50% RPS in California by 2030. The study finds that renewable integration challenges, particularly overgeneration during daylight hours, are likely to be significant at 50% RPS. The study indicates that at high penetrations of renewable generation, some level of renewable resource curtailment is likely to be necessary to avoid overgeneration and to manage net load ramps. The study also identifies a number of promising integration solutions that could help to mitigate overgeneration, including procurement of a diverse portfolio of renewable resources, increased regional coordination, flexible loads, and energy storage. Achievement of a higher RPS at least cost to electric customer will likely require implementation of a portfolio of integration solutions; timely implementation of these solutions is critical but would likely involve substantial challenges related to cost, feasibility, and siting. In this study, a 50% RPS is shown to lead to higher electric rates than a 33% RPS under a wide range of natural gas prices, CO_2 allowance prices, and renewable resource costs. The lowest-cost 50% RPS portfolio modeled here is one with a diversity of renewable resource technologies. The highest-cost portfolio modeled is one that relies extensively on rooftop solar photovoltaic systems. This study highlights the need for additional research in a number of areas, including the need to address sub-five-minute operational issues, ensure sufficient power system flexibility, and develop strategies to avoid overgeneration.