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Managing Solar Photovoltaic Integration in the Western United States

Power System Flexibility Requirements and Supply

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NOTICE

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Preface

This report is one in a series examining potential challenges related to planning future power systems with higher solar photovoltaic (PV) penetrations. In recent years, numerous renewable integration studies have examined power system operations with various wind and solar penetrations and have found it feasible to balance supply and demand. There are also examples of power systems currently operating with significant penetrations of wind or solar power in the literature. This series of reports focuses on solar PV generation specifically and delves deeper into potential integration issues that may not be so challenging at moderate penetrations but could be of more import at higher PV penetrations.

The series uses the western U.S. power system for these investigations because it is a region the authors and their colleagues have already extensively studied. We are therefore well-suited to analyze even higher PV penetrations and then examine the results in multiple models to determine whether our current approaches are missing key details that only emerge at higher PV penetrations. We also examine three regions in the western United States with significantly different existing power systems and connections to neighboring regions; this provides a more balanced picture as to how high PV penetration systems might emerge in different contexts and what the resulting issues, if any, might be.

The four publications in this series are listed and described in Table ES-1.

Table ES-1. Reports in the *Managing Solar Photovoltaic Integration in the Western United States* Series

Title	Description
Managing Solar Photovoltaic Integration in the Western United States: Power System Flexibility Requirements and Supply	**Assessment of net load ramping needs and what resources are available to provide upward and downward ramping at different timescales**
Managing Solar Photovoltaic Integration in the Western United States: Resource Adequacy Considerations	Probabilistic resource adequacy assessment of high PV penetration scenarios and comparison to planning reserve margin approaches using capacity value approximation methods
Behind-the-meter Solar Accounting in Renewable Portfolio Standards	An exploration of how two renewable portfolio standard design elements can influence the interaction of behind-the-meter PV and total renewable generation
Managing Solar Photovoltaic Integration in the Western United States Appendix: Reference and High Solar Photovoltaic Scenarios for Three Regions	Resource Planning Model (RPM) inputs, scenario framework, and results for RPM-AZ, RPM-CO, and RPM-OR; two of the papers in the series use these scenarios as their starting point for analysis

This report is listed in **bold type**.

This report series was commissioned by the Western Interstate Energy Board (WIEB) as part of the Enhanced Distributed Solar Photovoltaic Deployment via Barrier Mitigation or Removal in the Western Interconnection project funded by the U.S. Department of Energy (DOE) Office of

Energy Efficiency and Renewable Energy (EERE) Solar Energy Technologies Office (SETO).[1] For more information, including links to other reports, see https://www.westernenergyboard.org/western-interstate-energy-board/barrier-mitigation-to-enhanced-distributed-solar-photovoltaic/.

[1] An additional work was published as a journal article: Kenyon, Rick Wallace, Matthew Bossart, Marija Marković, Kate Doubleday, Reiko Matsuda-Dunn, Stefania Mitova, Simon A. Julien, Elaine T. Hale, and Bri-Mathias Hodge. 2020. "Stability and Control of Power Systems with High Penetrations of Inverter-Based Resources: An Accessible Review of Current Knowledge and Open Questions." Solar Energy, Special Issue on Grid Integration, 210: 149–68. https://doi.org/10.1016/j.solener.2020.05.053.

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The idea for this series of reports was developed with input from several of our colleagues at NREL and the project's technical advisory committee. Lori Bird, Kara Clark, Michael Coddington, Paul Denholm, Barry Mather, Michael Milligan, Bryan Palmintier, and Mark Ruth (NREL) provided input to an initial screening analysis of PV reliability barriers. The barriers screening analysis was then reviewed with the committee, as was a research plan developed in response to the screening results. We would like to thank committee members for their participation in those processes as well as for the review and guidance they provided throughout the execution of the research. The results and findings in this report and the broader project do not necessarily reflect their opinions or the opinions of their institutions. The committee is composed of the following individuals:

- Jim Baak, Vote Solar
- Guru Belavadi, Arizona Corporation Commission
- Ken Bolton, Western Electricity Coordinating Council
- Enoch Davies, Western Electricity Coordinating Council
- Tom Flynn, California Energy Commission
- Jennifer Gardner, Western Resource Advocates
- Daniel Haughton, Arizona Public Service Electric Company
- Carl Linvill, Regulatory Assistance Project
- Toby Little, Arizona Corporation Commission
- Clyde Loutan, California Independent System Operator
- Louise Nutter, Federal Energy Regulatory Commission
- Vijay Satyal, Western Electricity Coordinating Council
- Courtney Smith, California Energy Commission.

This report is one of a series. The authors would like to thank the other contributors to the report series, as well as Clayton Barrows, Dheepak Krishnamurthy, Ilya Chernyakhovskiy, Amy Rose, Dominique Bain, Jaquelin Cochran, and Mike Meshek of NREL and Alejandro Moreno of DOE for helpful input and feedback during both the analysis and the publication process.

[2] SEEDS2-SES is the Solar Energy Evolution and Diffusion Studies 2 – State Energy Strategies program. For information about the program, see https://www.energy.gov/eere/solar/solar-energy-evolution-and-diffusion-studies-2-state-energy-strategies-seeds2-ses.

Acronym List

APS	Arizona Public Service Company
ATB	Annual Technology Baseline
CAMX	California/Mexico
CC	combined-cycle
CEM	capacity expansion model
DOE	U.S. Department of Energy
EERE	Energy Efficiency and Renewable Energy
EIA	U.S. Energy Information Association
MW	megawatt
MWh	megawatt hour
NERC	North American Electric Reliability Corporation
NEVP	Nevada Power Company
NREL	National Renewable Energy Laboratory
NWPP-CA	Northwest Power Pool Canada
NWPP-US	Northwest Power Pool United States
PACW	PacificCorp West
PGN	Portland General Electric Company
PSC	Public Service Company of Colorado
PV	photovoltaic
ReEDS	Renewable Energy Deployment System
RMRG	Rocky Mountain Reserve Group
RPM	Resource Planning Model
RPS	renewable portfolio standard
SETO	Solar Energy Technologies Office
SRP	Salt River Project
SRSG	Southwest Reserve Sharing Group
TEP	Tucson Electric Power company
VG	variable generation
WACM	Western Area Power Administration: Colorado Missouri
WALC	Western Area Power Administration, Lower Colorado Region
WI	Western Interconnection
WIEB	Western Interstate Energy Board

Executive Summary

As penetrations of variable renewable energy generation technologies such as wind and solar photovoltaics (PV) continue to increase across the United States, greater uncertainty and variability in the net load often lead to a concern about how power systems may adapt. Managing the system net load (i.e., load minus contribution from variable generation technologies) may become more challenging with increasing variable generation, as the magnitude and frequency of net ramps increase. However, there is inherent flexibility in power systems through the conventional generator fleet (under least-cost unit commitment and economic dispatch), less-conventional generation sources (e.g., storage, demand response, concentrating solar power with thermal energy storage), and imports and exports with neighbors. In this analysis, we create an open-source tool to analyze the flexibility of the results of a specific commercial unit commitment and economic dispatch tool (PLEXOS), but the code can be applied generically as well. The tool assesses the flexibility *requirements* (or demand) of a system through a net load analysis. The constraints and limitations of each generator are then considered to determine the *availability* (or supply) of flexibility. Then, the supply and demand of flexibility are compared to gain a more complete picture of potential flexibility concerns.

We apply this open-source tool to high-penetration PV scenarios constructed for three focus regions in the western United States defined using the Resource Planning Model (RPM) capacity expansion modeling tool: RPM-OR, RPM-CO, and RPM-AZ. Generally, we find few flexibility concerns, as the western United States represents a large and interconnected power system with significant inherent flexibility. In addition, the PV scenarios we analyzed are generally high on capacity, leaving plenty of ramping ability on the system. We do find that for each focus region, the impact of imports on meeting ramping needs is essential. This means the PV integration in each focus region impacts the entire rest of the system. Each system has different dominant sources of flexibility. The conventional generator fleet (especially coal and gas combined-cycle technologies) as well as less-conventional sources such as storage are all shown to be important sources of flexibility. In reality, none of the three focus regions likely will deploy PV in isolation, meaning the ability of imports and exports to provide flexibility may be considerably different in scenarios with strong PV deployment in *every* region.

Overall, we intend that the framework we present here will be useful in future analysis of other system evolutions to identify whether and how flexibility may constrain the successful deployment of variable generation technologies.

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1 Introduction

The cost of solar photovoltaics (PV) has declined dramatically in recent years (Lazard 2018). The resulting increasing shares of electricity from PV are leading to concerns about change in the shape of the net load (i.e., demand for electricity minus contributions from wind and PV) (Denholm et al. 2015). Several aspects of the diurnal pattern of PV generation are of interest at high penetrations, including the low level of net load in the middle of the day, the shifting of system net load peak to evening hours, a narrower system peak during those evening hours, and the steep ramps during the transition to and from daylight hours. This report focuses on the latter issue of ramping within a generalized framework developed to analyze system flexibility.

1.1 Power System Flexibility

Operating the power grid requires balancing supply and demand over many timescales and in every instant. Demand is constantly changing, and as a result, supply must as well. Renewable energy, such as PV and wind, can further complicate system operation by increasing net load uncertainty and variability, potentially requiring larger quantities of operating reserves and increased ramps from the rest of the generator fleet. In short, renewable energy from variable resources often leads to a requirement for greater grid flexibility (Cochran et al. 2014).

Operational flexibility is inherent to the grid through the economic unit commitment and dispatch of the generator fleet. However, the flexibility of any given unit depends on technology characteristics as well as institutional considerations (Cochran et al. 2014; Schlag et al. 2015; Mills and Seel 2015). For instance, thermal generators are characterized by their ramp rates, maximum capacity, minimum generation level, minimum up/down time, and other attributes. These are often determined by the physical constraints of the generator. For example, it typically takes hours to days to turn on large steam turbines, such as those used for coal-fired generation. Smaller combustion turbines, such as those often fired by natural gas, can start up in a matter of minutes. On the other hand, a large coal-fired steam turbine may have a larger capacity to ramp up over, say, an hour, whereas the smaller combustion turbine might be limited by its small capacity. The point is that each individual generator has a series of constraints that define its ultimate flexibility and those constraints are not always easily generalizable. For instance, some constraints are dictated by grid conditions, not generator physics. Examples of this include generators that are denoted as “must-run” due to their role in providing important grid services, (such as maintaining steady voltage or frequency), contractual obligations such as bilateral agreements, and constraints imposed by the natural gas supply system and fuel contracts.

Physical flexibility of a generator cannot necessarily be defined by the type of generator either. For example, some small hydro plants operate on a run-of-river basis, meaning their energy production depends on the flow of a river; these plants are not equipped with supporting infrastructure that would provide more control. As a result, their output tends to change frequently, similarly to PV and wind, with hour-by-hour variations and somewhat predictable seasonal trends. Run-of-river hydro generators can thus be quite inflexible due to their inability to change their generation setpoints.[3] However, many large hydro plants draw their kinetic energy from water in a reservoir contained by a dam. These types

[3] Run-of-river plants are not always inflexible. In fact, many hydro resources along the Columbia River in the Northwest United States are classified as run-of-river but are large and have much more flexibility than stated here.

of hydro plants typically store several days' or even weeks' worth of energy, can start up with little notice, and can thus be operated flexibly.[4]

Storage (in the form of pumped hydro storage, batteries, or thermal storage associated with a concentrating solar power plant) also provides important flexibility to the system (Denholm et al. 2015; Denholm and Hand 2011). Though storage is generally a flexible resource, it is inherently energy-constrained, and it may be subject to additional considerations. Large pumped hydro storage plants can be subject to recreational and ecological constraints similar to those at large hydropower plants. Batteries have extremely fast ramp rates, but they are currently expensive to configure with long-duration energy capacities. Concentrating solar power with thermal energy storage has more flexibility than most types of solar power due to its stored energy capacity, making it valuable when the sun is not shining (Jorgenson, Denholm, and Mehos 2014). However, concentrating solar power is still energy-limited, and its power block has the same constraints as other steam-powered turbines. Demand response is another example of an energy-limited form of grid flexibility, although to date, its potential has not been fully realized, especially for grid services such as energy shifting and ramping (Ma et al. 2013).

In large interconnected power systems, some flexibility also comes from long-distance, transmission-enabled imports and exports. This type of flexibility is complicated by the fact that various regions and entities have different contracts and agreements under which power is exchanged. The flexibility of imports and exports can be difficult to quantify not only because of various institutional and contractual constraints, but also because of the complex rules that govern power flow (Makarov et al. 2009).

Less favorable sources of flexibility exist as well. For instance, a system may operate with fewer ancillary services, or it may use capacity held as reserves to provide a different type of flexibility. Ancillary services are a class of system resources that represent spare or "unloaded" capacity on the generator fleet that can be called on in the event of planned or unplanned deviations in expected net load. Some types of reserves (often called load-following or flexibility reserves) actually exist to help deal with expected deviations in the net load (Hummon et al. 2013). Using other types of reserves for flexibility (e.g., contingency reserves, which are held to address large outages on the system) is not preferred, because the system would be resource deficient if an unexpected outage were to occur.

Another example of a less favorable form of flexibility is variable generation curtailment in which, for example, PV or wind generators are turned down or off when the system cannot accommodate the extra energy or variability of their output. Although curtailment is useful and necessary at times to provide reliable system operations, it is in another sense a waste of zero-marginal cost energy that could—in a sufficiently flexible system—be used to displace more expensive generation.

Dropped load is the least favorable source of flexibility. Because serving load is the primary purpose of power systems, dropped load is never desirable; however, unserved energy is a technically viable source of flexibility that is usable as a last resort. Furthermore, limited quantities of unserved energy are preferable to widespread, uncontrolled service losses.

[4] Hydropower flexibility varies significantly by plant. In addition to being of different sizes, each reservoir is subject to location-specific constraints, many of which have nothing to do with electricity generation. For example, recreational or ecological considerations, such as maintaining lake level or dissolved oxygen concentration, may take priority over grid needs thus reducing flexibility and responsiveness to grid conditions.

As Table 1 shows, there are many sources of flexibility on the system, some of which are more desirable than others:

Table 1. Sources of System Flexibility[a]

Flexibility Source	Pros	Cons
Generator fleet	Flexibility is usually well-characterized by dispatch constraints (e.g., ramp rate, capacity, minimum stable level, minimum up and down time, must-run status).	May have additional constraints not captured by dispatch constraints, which can vary generator by generator and depend on overall system conditions. One significant example is the considerable constraint imposed by the natural gas supply system.
Demand response	Can have fast response time and low cost; peak shaving/capacity service from some sectors and end-uses is well established.	Coordinating many end-use devices to provide more-continuous services such as energy-shifting and ramping in a dependable manner is complex and as yet unproven at scale.
Imports and exports	Can be a significant source of flexibility in a highly interconnected system	Physical constraints (governed by power flow and thermal limits) and institutional constraints (contracts, agreements) are often binding.
Renewable energy curtailment	If properly equipped, renewable energy can be quick to respond.	Curtailments are a waste of zero-marginal cost electricity that result in lower capacity factors for renewable energy plants and fewer emissions benefits.
Unserved reserves	Close to a last resort for flexibility	Using reserved capacity to provide other services leaves the original variability or uncertainty risk uncovered, exposing the system to the possibility of a larger failure.
Load shedding	Last resort for flexibility; may be able to prevent a more widespread disturbance	Some customers completely lose service.

[a] The table generally shows the pros and cons with each type of flexibility from a technical standpoint. This analysis does not consider the economic cost of using each flexibility resource, or initial capital costs.

Previous work has considered various methods for quantifying flexibility (Cochran et al. 2014; Schlag et al. 2015; Mills and Seel 2015; Makarov et al. 2009; Lannoye, Flynn, and O'Malley 2012). The work presented here formalizes some of NREL's previously used, but currently unpublished methods that fully analyze annual unit commitment and economic dispatch results to quantify flexibility by both documenting them and adding the calculations and visualization outputs to an existing open-source tool, NREL's Multi-Area Grid Metrics Analyzer. [5] MAGMA was specifically designed to create reproducible, standardized outputs from PLEXOS (2018), a commercial unit commitment and economic dispatch model. Even though MAGMA is currently limited to analyzing PLEXOS outputs, the

[5] http://github.com/NREL/MAGMA

methodology and metrics presented here, because available as an open-source tool, can be extracted and applied to other unit commitment and economic dispatch models.

1.2 Capturing High-PV System Flexibility Needs in Planning Tools

At high penetrations, PV generation increases net load variability by imposing a very distinctive diurnal pattern with large ramps every morning and evening as the sun rises and sets. Furthermore, weather variations, such as cloud cover or dust storm activity, impact PV output and thus net load. This represents an increase in flexibility demand over timescales of a few minutes to a few hours that the rest of the generator fleet and other resources must meet to balance load and thereby maintain system frequency. The diurnal generation pattern also results in low net load conditions in the middle of the day. At times, a power system may be unable to ramp down enough generators or export enough excess power to absorb all the nominally available PV generation. In this case, PV generation will be curtailed; that is, the system will be unable to provide the flexibility implicitly requested by PV plants. In turn, the PV plants are required to provide that flexibility themselves in the form of curtailment, despite having zero marginal cost.

These phenomena are difficult to capture in the least-cost, optimal investment planning tools that are often used to determine which new generators, transmission lines, and other resources are needed to maintain reliable operations as load grows and older equipment retires. The primary difficulty lies in temporal resolution. Capacity expansion models (CEMs) are subject to high computational demands because they seek optimal decisions over decadal timescales; low temporal resolution is a common strategy used to preserve important details elsewhere (Sullivan, Eurek, and Margolis 2014; Mai et al. 2015). However, the low net load and ramping conditions just described are an hourly or even sub-hourly phenomena driven by unit commitment and ramping constraints. To accurately estimate how much PV capacity is economic to build, capacity expansion models must estimate how much PV curtailment is to be expected in a wide variety of candidate systems, and they must also select appropriate complementary resources able to effectively integrate PV into daily operations. Since CEMs are generally not designed to incorporate large seasonal changes, the analysis can be supplemented with a production cost model to better capture operations.

We outline a methodology and metrics for comparing the supply and demand of system flexibility to gain insight into the flexibility inventory of a system, and we apply that methodology to analyze the ability of a planning tool to construct reliable high PV penetration systems in the western United States. First, in Section 2, we discuss the quantification of the system flexibility requirements (or demand) before detailing the method to compute the available flexibility (or supply). In Section 3, we apply this methodology to a set of high PV scenarios in the western United States.

2 Flexibility Inventory

2.1 Quantification of the Requirement for Power System Flexibility

For purposes of illustration, we create a test system that is composed of only five generators, as described in Table 2. The four thermal generators are named to illustrate their marginal cost, or merit order in a least-cost dispatch. The Baseload generator has the lowest marginal cost and thus is dispatched first to meet load (although it is also the least flexible, as indicated by the parameters in Table 2). The Intermediate generator has a slightly higher marginal cost, and slightly more flexibility. The Peaker and Super Peaker have the highest marginal cost but the most dispatchability. The Solar plant is a variable generation resource with zero marginal cost, dispatchable downward through curtailment but limited by the solar availability in any given hour. We use three scenarios (Base, 2x Solar, and 4x Solar) in which the Solar PV generator is scaled by two times and four times, respectively, to illustrate the impact of increased PV on system flexibility. Table 2 illustrates three capacities for the PV plant, one each for the Base, 2x Solar, and 4x Solar cases respectively.

Table 2. Characteristics of Five Generators Modeled in a Test System as a Simple Example of Flexibility

Generator Type	Variable Cost ($/MWh)	Max Capacity (MW)	Min Stable Level (MW)	Max Ramp Up (MW/min.)	Max Ramp Down (MW/min.)	Min Up Time (hr.)	Min Down Time (hr.)
Baseload	20	100	60	3	3	12	12
Intermediate	40	150	30	3	3	6	6
Peaker	80	100	40	10	10	1	0
Super Peaker	120	50	20	10	10	1	0
Solar	0	40, 80, or 160	0	N/A	N/A	0	0

MW = megawatt; MWh = megawatt hour

The requirement for flexibility (or flexibility demand) is straightforward. It is a simple timeseries analysis of the net load (i.e., electricity demand minus contributions from variable generation (VG) resources such as wind and PV). For the purposes of this flexibility inventory, we consider the contributions from variable generation resources *post-curtailment.* Thus, the flexibility provided by variable generation in its ability to curtail is already included and not explicitly calculated here as a source of flexibility. The goal of the flexibility inventory is to analyze the ability of the rest of the generator fleet to meet variations in the net load, and most of these variations are the direct result of adding variable generation to the system. In this sense, curtailing variable generation is just fixing the "problem" it created, which is why it is not included in this flexibility inventory.[6] Figure 1 shows the average diurnal net load curves for the test system under the three solar scenarios for four seasons. The figure indicates a duck-shaped curve for the increased solar scenarios, especially in the low-load seasons of spring, fall, and winter. This shape is characterized by low net load in the middle of the day due to the presence of solar, and ramps in the morning and evening during sunrise and sunset respectively. For

[6] This is an over-simplification. At times, VG may reduce variation in net load; however, this case is less common. Future work on this flexibility inventory may include the ability to include curtailment as an explicit, rather than implicit, flexibility mechanism.

the Base and 2x Solar cases, the net load (solid line in Figure 1) and "potential net load"[7] (dashed line in Figure 1) are identical, indicating that all solar is used and no curtailment occurs. However, the 4x Solar case does show a difference in net load and potential net load, indicating that curtailment is occurring during the middle of the day for most seasons, but least so in summer when load is highest.

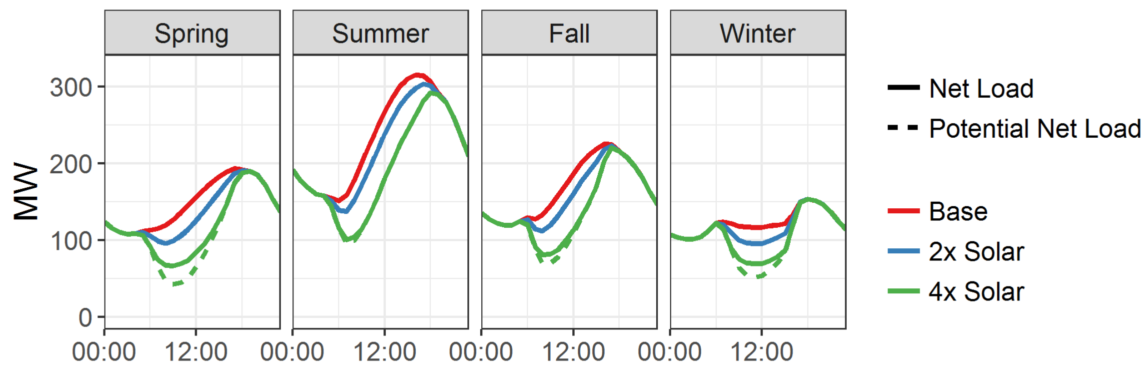

Figure 1. Diurnal net load curves for three solar scenarios in a test system

Using the timeseries net load data, we can also construct a duration curve of load and net load, which sorts the timeseries from highest to lowest, shown in Figure 2. These plots indicate the magnitude of both high and low net load levels, and the frequency with which they occur throughout the year. Figure 2 shows that the load (solid line) curve does not change in the three scenarios, but the net load curve moves downward as PV increases.

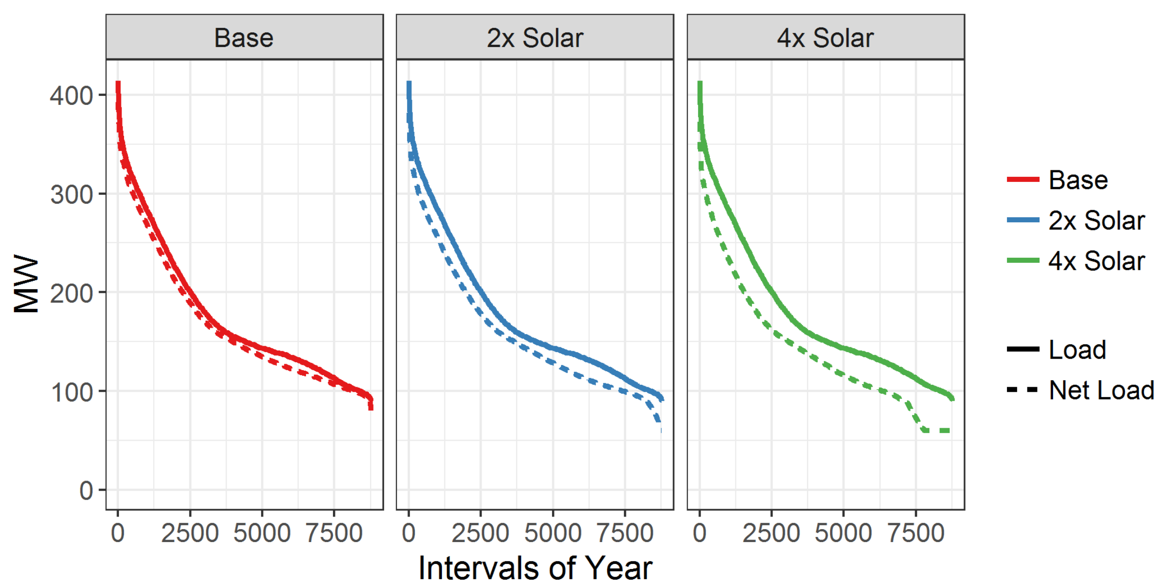

Figure 2. Load and net load duration curves for three solar scenarios in a test system

Importantly, flexibility should be quantified over multiple timescales. Flexibility solutions over, for example, 15 minutes or 1 hour might look very different from flexibility solutions over 36 hours (Mills and Seel 2015). For this analysis, we focus on flexibility time frames of 1 hour, 3 hours, 6 hours, and

[7] Potential net load can also be thought of as "pre-curtailment" net load, whereas net load includes curtailment.

36 hours.[8] Next, we can quantify the magnitude of net load ramps over each of those time frames and compare the distribution of these ramps across our three solar scenarios. Figure 3 shows the distribution of one-hour ramps for three variables: VG potential, load, and net load. VG potential represents the available, in this case, PV energy before any curtailment. Net load is the system load minus the VG potential. As solar increases through the three scenarios, the absolute VG potential ramps naturally increase as well, although the distribution is somewhat skewed by the large number of overnight (zero ramp) hours. Load ramps are consistent across all three scenarios because load is unchanged. The net load ramp distribution, however, flattens out across each scenario as more solar is added and net load ramps generally increase. We also see a slight asymmetry in the shape of the distribution as the magnitude of up net load ramps increases. This is due to the correlation between load up-ramps and solar down-ramps (as the sun sets, lights go on and residential demand increases). The bottom frame of Figure 3 is a good reminder of the requirement to analyze and quantify flexibility need. At higher amounts of VG, the distribution of net load ramps sees longer and bigger tails, indicating both that the magnitude and frequency of net load ramps are increasing. This underscores the importance of quantifying the need for flexibility at greater VG penetrations and for quantifying the supply of flexibility available, as will be discussed in the following section.

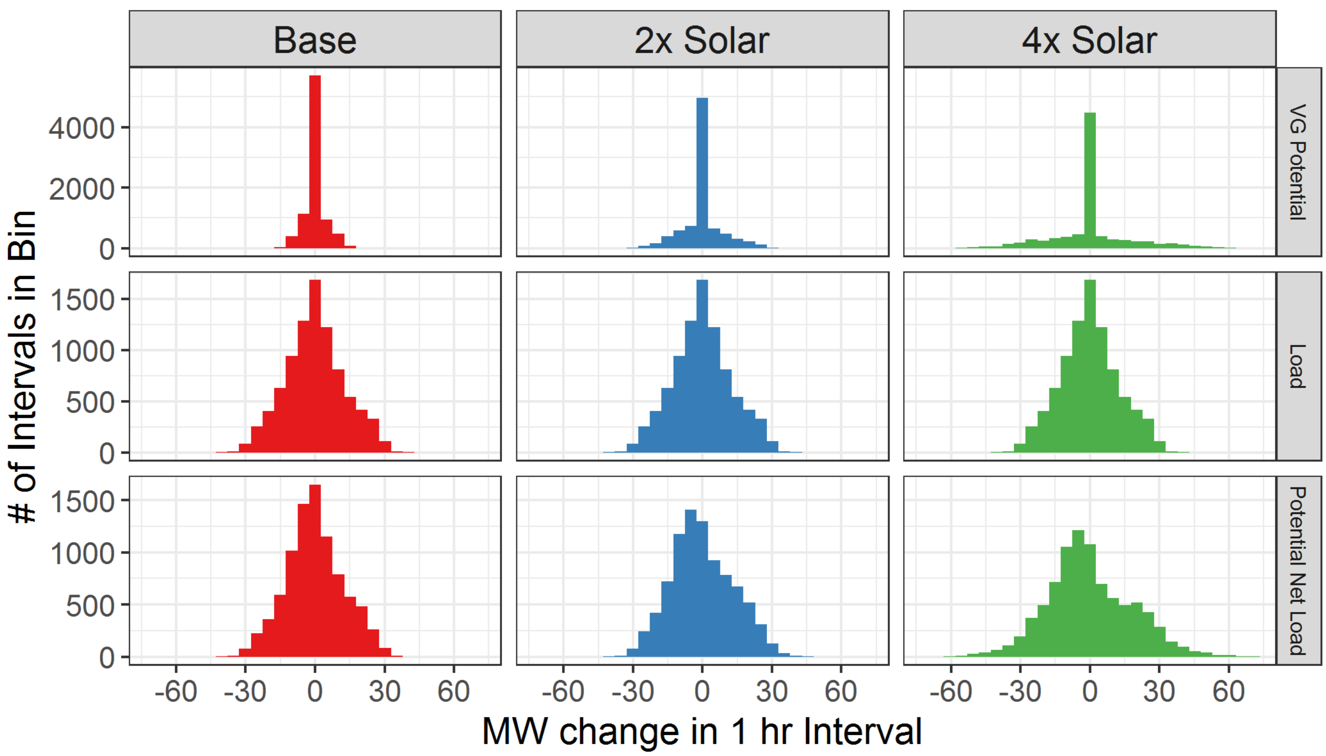

Figure 3. A quantification of one-hour ramps in VG potential, load, and net load for three solar cases in a test system

Finally, the largest ramps (the tails of the "potential net load" distribution in Figure 3 above) are computed. Figure 4 indicates the largest ramps in the 4x Solar case, which has the highest potential for

[8] These time frames are used simply for illustration. For the flexibility inventory tool used here, any time frame can be used. Because one hour is the smallest interval of timeseries data, this is the shortest flexibility time frame we analyze. Ideally, higher-resolution data would be used as an additional time frame.

net load ramps. The ramps are highlighted in the orange box for each time frame. In this case, most of the largest ramps occur during the low-load, high-solar months of April and May. We can compute additional statistics on the ramps as well, as detailed in Table 3 for the flexibility time frame of three hours. Note that there is clearly an increase in ramps (both average and the standard deviation) as solar PV increases. Some flexibility computations in the past have used three standard deviations of net load ramp as a metric for comparing flexibility requirements (Mills and Seel 2015). However, the table shows that the maximum net load ramp is (in all cases) significantly higher than the three standard deviation metric, so computing the maximum ramp can be an important indication of flexibility needs.

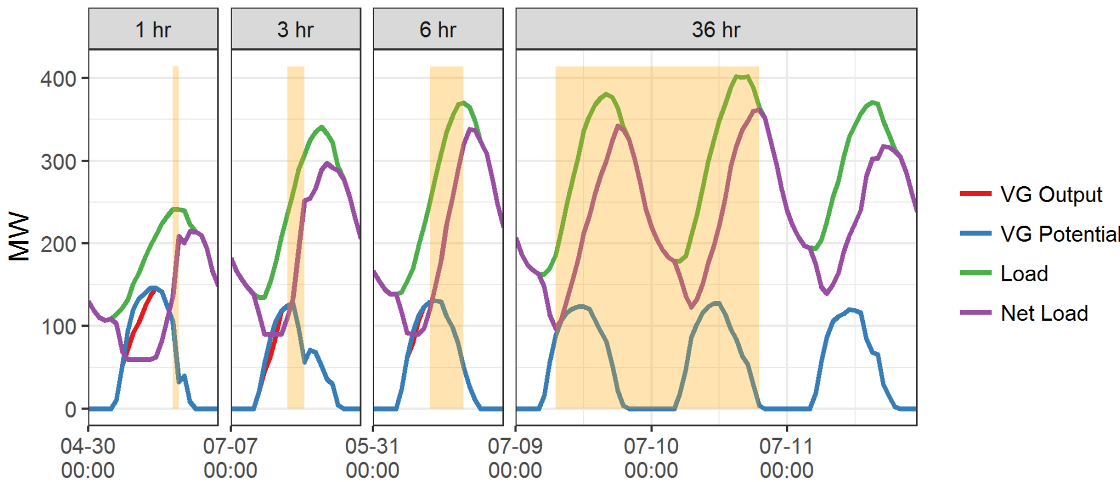

Figure 4. Timeseries (with x-axis indicating date and time) showing the largest 1-hour, 3-hour, 6-hour, and 36-hour ramps in the 4x Solar Case, which largely occur during the relatively low-load but high solar spring season

The orange box represents the time frame for the largest net load ramp.

Table 3. Net Load Ramp Statistics for the Three Solar Cases Over the Three-Hour Time Frame

3-Hour Upward Net Load Ramps	**Base**	**2x Solar**	**4x Solar**
Average ramp up (MW/3 hrs.)	26.5	31.4	42.7
Standard deviation ramp up (MW/3 hrs.)	22	22.6	29
Three standard deviations of ramp up (MW/3 hrs.)	66	68	87
Maximum ramp up (MW/3 hr)	99	106	140
Maximum ramp up date	08/13 8:00	07/07 10:00	07/07 10:00
3-Hour Downward Net Load ramps	**Base**	**2x Solar**	**4x Solar**
Average ramp down (MW/3 hrs.)	26.9	26.9	32.2
Standard deviation ramp down (MW/3 hrs)	20	19	20
Three standard deviations of ramp down (MW/3 hrs.)	61	57	60
Maximum ramp down (MW/3 hrs.)	94	94	94
Maximum ramp down date	07/16 20:00	07/16 20:00	07/16 20:00

2.2 Quantification of the Availability of Power System Flexibility

As discussed in Section 1, many factors impact the flexibility of any given generator. Figure 5 depicts the algorithms we use to determine the flexibility of a conventional generator over a given time frame (e.g., 1 hour, 3 hours, 6 hours, and 36 hours). As the figure indicates, generator parameters such as minimum up time, minimum down time, max capacity, minimum stable level, ramp rate, and reserves provision must be considered to realistically characterize how much flexibility a generator can provide at a certain time. The time frame is an important consideration as well. A baseload plant will likely not be able to turn off or on in a one-hour time frame but would probably be able to do so in 36 hours. Thus, a baseload power plant might be able to offer much more flexibility in 36 hours, whereas a quick-starting peaker plant likely would have the same amount of flexibility to offer in one hour and 36 hours.

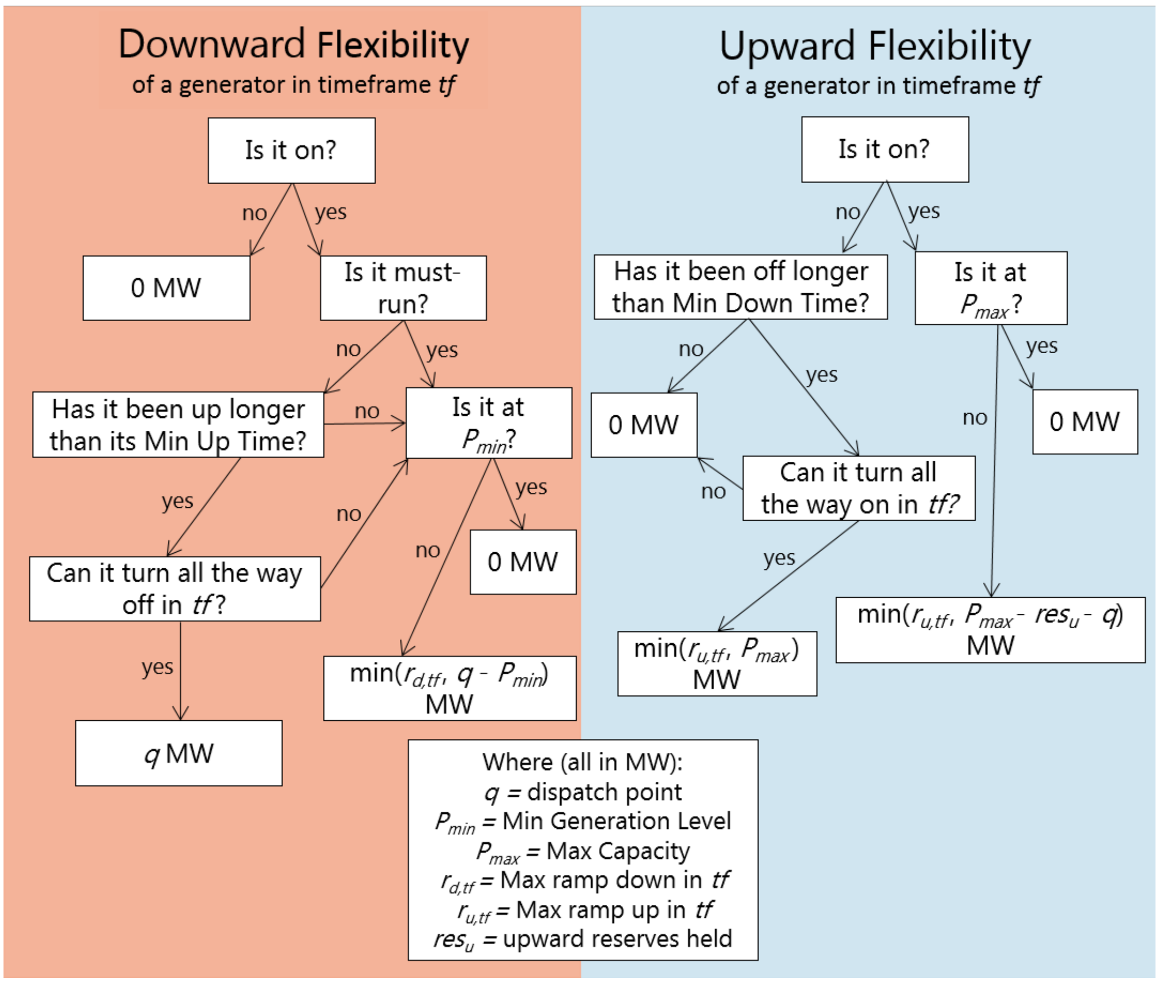

Figure 5. Logic flow for determining the upward and downward flexibility of a generator in a given time frame

This logic chart is a simplified example, as generators can require significantly more complex logic and additional variables.

Figure 5 offers logic to determine the flexibility of conventional thermal power plants, but it can also be useful in assessing the flexibility of other types of generation, such as storage and hydropower. However, a modified version of the logic tree is needed to incorporate the complexities of these generation types. Even different types of storage may have different considerations. For example, pumped-storage hydropower uses a turbine and pump to generate or store energy. These turbines and pumps often have similar parameters to thermal generators, such as ramp rates, and minimum up and down times. However, pumped-storage hydropower offers additional flexibility through its ability to switch between pumping and generating modes. For instance, a pumped-storage hydropower unit that is pumping at maximum has roughly twice the amount of upward flexibility because of the ability to turn off the pump and to then generate as well. Battery storage is similar but is not constrained by ramp rate or minimum generation levels. The flexibility of storage technologies can be considered in the flexibility inventory, but with slightly different logic. However, one large caveat applies to all types of storage flexibility, and that is their energy-constrained nature: pumped hydropower plants, battery energy storage, demand response, and other such technologies all store energy in a finite reservoir whose size and current state must be accounted for in the flexibility logic. To use our previous example, just because a pumped-storage hydropower unit is pumping and could switch into generation mode does not guarantee there will be enough energy in the reservoir to support that flexibility.

We use the same test system and scenarios from Section 2.1 to indicate the results of flexibility supply profile. The logic is applied to every generator in every time step, for every flexibility time frame. The results can then be examined on an aggregate basis, on a seasonal basis, or even at a single time frame. For instance, Figure 6 illustrates the aggregate one-hour flexibility of the generator fleet averaged across every hour in the year for the three scenarios. The positive y-axis indicates upward flexibility and the negative y-axis indicates downward flexibility.[9] Note that the Baseload generator has the most downward flexibility, as it is dispatched first and operates with the highest load factor. The Intermediate generator has similar upward and downward flexibility, and the Peaker plants have mainly upward flexibility because they are rarely dispatched but are quick to start in the one-hour time frame. Note that across the three scenarios, the changes to aggregate flexibility are relatively small.[10] Overall, there is slightly less downward flexibility from baseload (with a corresponding increase in upward flexibility) as it is dispatched downward to accommodate the increased solar energy. The same trend can be seen in the other generator categories as well.

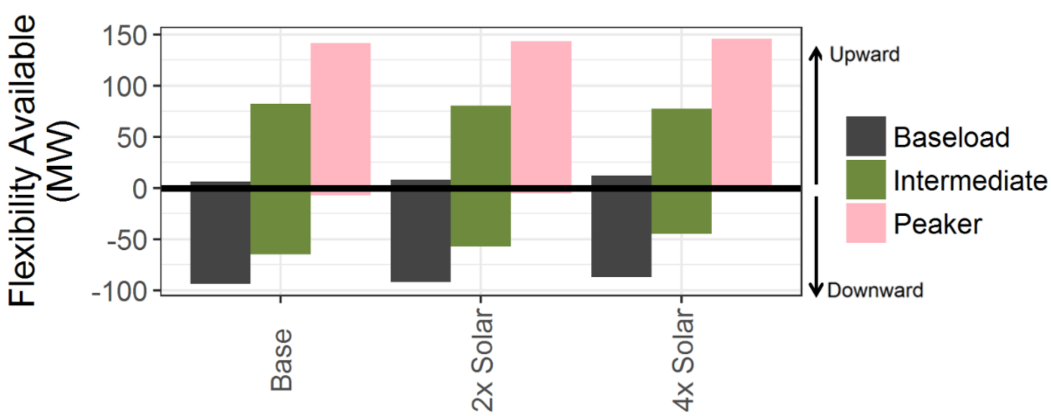

Figure 6. Aggregate average one-hour flexibility by generator type for three scenarios

The positive y axis indicates upward flexibility and the negative y axis indicates downward flexibility.

[9] A generator can have both upward and downward flexibility at the same time.

[10] The three simplified scenarios here increase solar generation without a corresponding decrease in conventional generation capacity. In reality, solar may be added instead of conventional generation capacity (or in tandem with retiring generation). The loss of conventional generation capacity would result in a decrease in flexibility available from those sources.

We can also examine a less temporally aggregated flexibility profile, shown in Figure 7. This figure illustrates a concept similar to that in Figure 6, average one-hour flexibility, but broken into hour of the day and season of the year. For the Base case, the summer season has the highest average load, and thus the overall lowest upward flexibility as generators are dispatched higher, with the peaker plants being dispatched to help with the evening peak, resulting in the lowest upward flexibility available over the course of the year. Perhaps intuitively, the lowest downward flexibility occurs in the lowest-load months of the year with the least online generation (middle of the night in winter, in this case). Across scenarios, we see that as we add solar, the lowest amount of upward flexibility period is still generally occurring during summer peak but pushed slightly later in the evening after the sun has set and solar generation goes to zero and other generators pick up the slack. We also see a shift in when the lowest downward flexibility occurs; it is still in the low-load winter and spring, but it is during midday instead of the middle of the night. The thermal generation has backed down to accommodate solar, resulting in less downward flexibility available in the middle of the day.

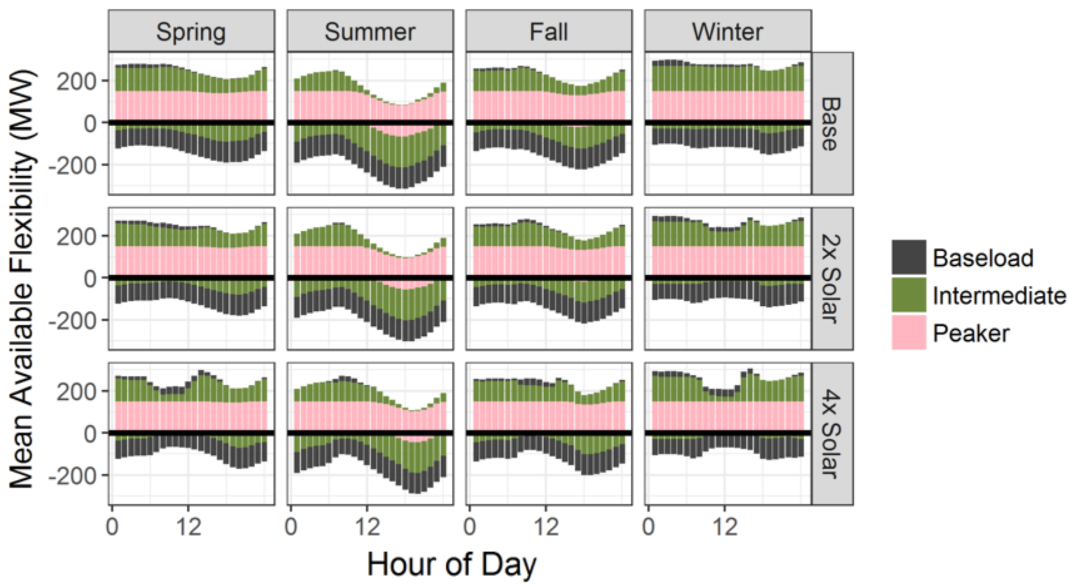

Figure 7. Mean available one-hour flexibility on an average day in four different seasons for three scenarios

The positive y axis indicates upward flexibility and the negative y axis indicates downward flexibility.

2.3 Flexibility Inventory Metrics

The third segment of the flexibility analysis is to compare the supply and demand of flexibility to get a clear picture of when, where, and how frequently flexibility shortages may occur. First, a simple timeseries comparison of the flexibility supply and demand can indicate the hours in which the inventory (i.e., the difference between flexibility supply and flexibility demand) are the lowest. Table 4 shows the inventory results for the three test scenarios.

It is important to remember that calculating the flexibility inventory is not directly included in the optimization that leads to the commitment and dispatch of the generator fleet. Therefore, these numbers are simply an analysis of the optimized dispatch, keeping in mind that a different dispatch in a given time frame could lead to more or less flexibility. This is simply the inherent inventory as a result of the dispatch. The results of such a small test system are somewhat difficult to interpret. For many time frames, more flexibility might actually be available in the higher solar PV scenarios because there is more spare capacity available as PV displaces the thermal generators. So, the results in Table 4 are only indicative for these three simple scenarios and are not generalizable for higher PV scenarios. But they do indicate the types of metrics available under the flexibility inventory.

Table 4. Lowest-Flexibility Inventory Periods for Three Test Solar Scenarios

Scenario	Flexibility Interval (hrs.)	Lowest Upward Inventory (MW)	Lowest Upward Inventory Time (month/day time)	Lowest Downward Inventory (MW)	Lowest Downward Inventory Time (month/day time)
Base	1	18.4	08/08 17:00	10.0	01/02 01:00
	3	18.4	08/08 17:00	10.0	01/02 01:00
	6	18.4	08/08 17:00	10.0	01/02 01:00
	36	7.3	08/12 02:00	77.1	03/18 08:00
2x Solar	1	27.6	08/08 16:00	60.0	01/02 01:00
	3	27.6	08/08 18:00	60.0	01/02 01:00
	6	27.6	08/08 18:00	14.0	01/02 00:00
	36	21.2	08/08 18:00	60.0	03/18 12:00
4x Solar	1	18.4	08/08 17:00	10.0	01/02 01:00
	3	18.4	08/08 17:00	10.0	01/02 01:00
	6	18.4	08/08 17:00	10.0	01/02 01:00
	36	7.3	08/12 02:00	77.1	03/18 08:00

Although Table 4 highlights the minimum flexibility inventory periods, we can also examine an annual duration curve to get a better idea of how the other hours of the year compare. Figure 8 shows these curves for one-hour flexibility inventory. The figure indicates there is not much difference in the downward flexibility inventory across scenarios on the whole. However, there is a visible difference in the upward flexibility duration curves, with greater flexibility available in the 4x Solar case. Again, for this simple example, we added solar to the system without taking anything away, which leads to more available flexibility in the higher solar cases as PV displaces thermal generation (thus reducing the capacity factor of the thermal generators) and leaves more of its capacity available during solar hours.

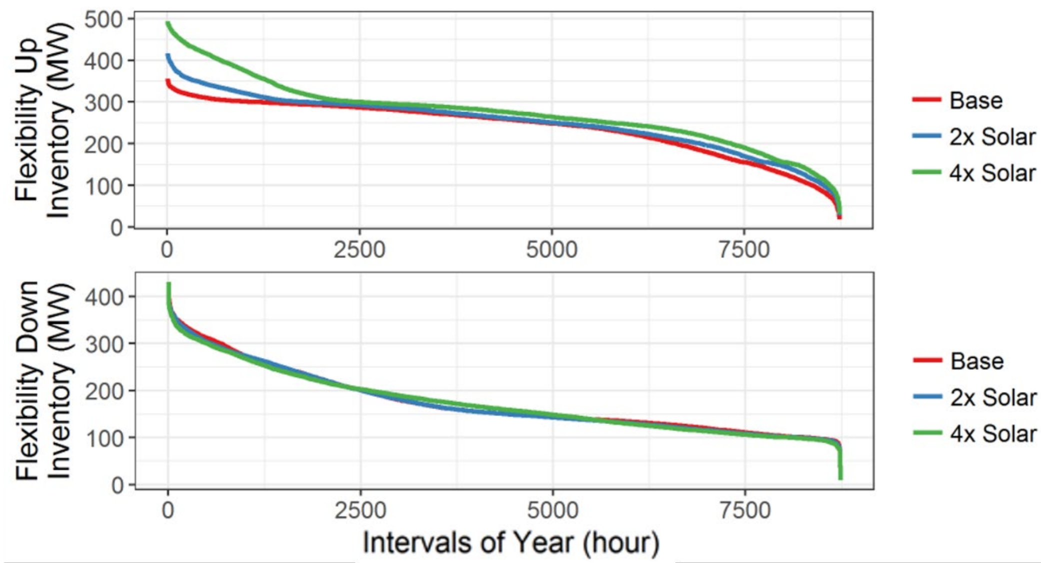

Figure 8. Duration curves of total one-hour flexibility for each hour of the year, in decreasing order

In addition to looking at the lowest inventory periods, our analysis includes a diurnal analysis to pinpoint the time of day and season that these low inventory periods are likely to occur. For instance, Figure 9 indicates the average daily one-hour flexibility surplus in both the upward and downward directions. Instead of identifying the very lowest surplus period, Figure 9 indicates recurring patterns when low surplus may occur. For instance, across all three solar scenarios, the lowest upward surplus occurs during evening peak hours, whereas the lowest downward surplus occurs during the overnight low load periods. We can also see the impact of increasing PV on the flexibility surplus. We largely see more upward flexibility surplus as we add PV and dispatch the other generators downward.

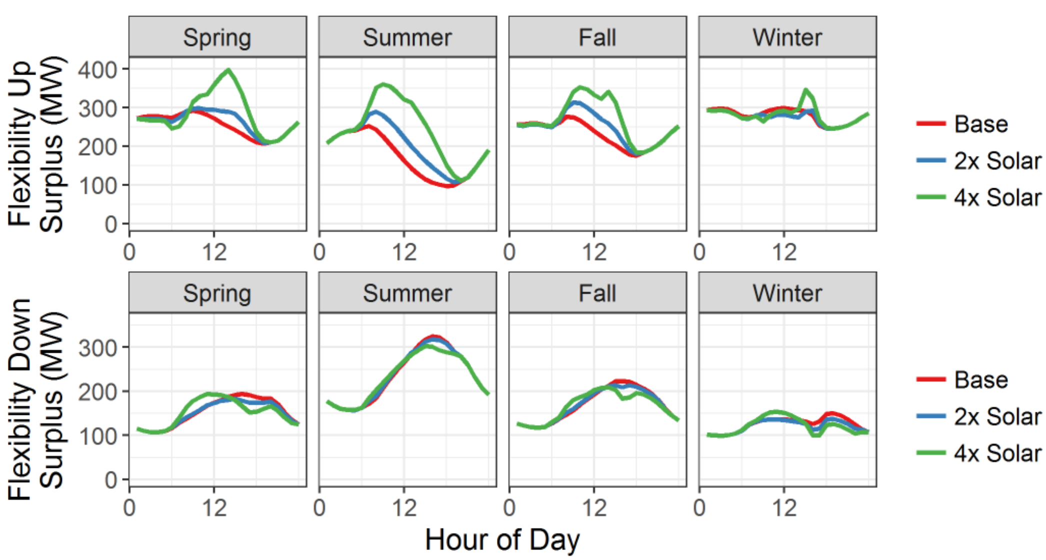

Figure 9. One-hour flexibility surplus for an average day in each of four seasons for three solar scenarios

We can also determine the sources of flexibility that contribute to meeting the largest ramps in net load. For instance, Figure 10 shows the largest upward and downward 3-hour net load ramp for the 4x Solar case. The largest upward and downward ramps actually are occurring (in this case) during the same season. The largest downward ramp occurs during the nighttime, meaning it is independent of solar and the Intermediate load plant is solely responsible for the sustaining ramp. The biggest upward ramp in net load actually seems to be occurring on a partly cloudy day when solar drops off fairly rapidly in the afternoon, but loads continue to increase (presumably driven by cooling loads). All three generator types (Baseload, Intermediate, and Peaker) contribute to meeting this increase in net load.

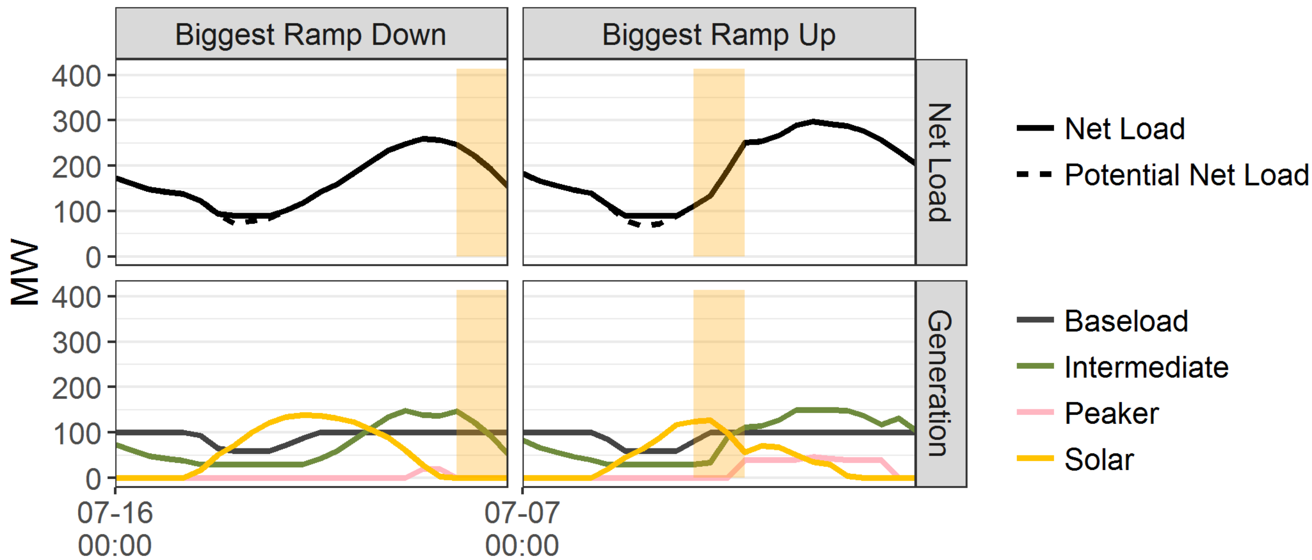

Figure 10. Largest upward and downward three-hour net load ramps over the course of the year for the 4x Solar case (top panel), and how ramps are met with the generator fleet (bottom panel)

Although these simple scenarios are instructive to show the capabilities of the flexibility inventory, the results are somewhat limited because the system is not complex or realistic. Next, we apply the flexibility inventory calculations to a larger system.

3 Flexibility in High PV Scenarios in the Western United States

For this analysis, we aimed to analyze the impacts of high amounts of PV on the flexibility and ramping characteristics of a large and realistic system. To that end, we used a regional capacity expansion model called the Resource Planning Model (RPM)[11] to create scenarios of high PV in the Western Interconnection (WI) of North America.

RPM projects least-cost capacity and transmission expansion every five years through 2035. It represents a single interconnection; this study focuses on the Western Interconnection, which includes 36 model balancing authorities as the primary regions in RPM. Embedded within this structure, the model has a focus region, in which generation units, transmission lines, and loads are represented at a high level of detail, and the optimization is carried out nodally. Outside the focus region, load and generators are aggregated, and transmission is modeled zonally. The underlying data used to construct this model come from Lew et al. (2013). Announced retirements, generators under construction, fuel costs, and technology costs are exogenous to the model and updated regularly (EIA 2018; Hale, Stoll, and Mai 2016; NREL 2018; Ventyx 2010). For this analysis, we study three focus regions defined by different groups of balancing authorities (Figure 11):

- RPM-AZ comprises Nevada Power Company (NEVP), Western Area Power Administration, Lower Colorado Region (WALC), Salt River Project (SRP), Arizona Public Service Company (APS), and Tucson Electric Power Company (TEP).
- RPM-OR comprises Portland General Electric Company (PGN) and PacificCorp West (PACW).
- RPM-CO comprises Public Service Company of Colorado (PSC) and Western Area Power Administration: Colorado Missouri (WACM).

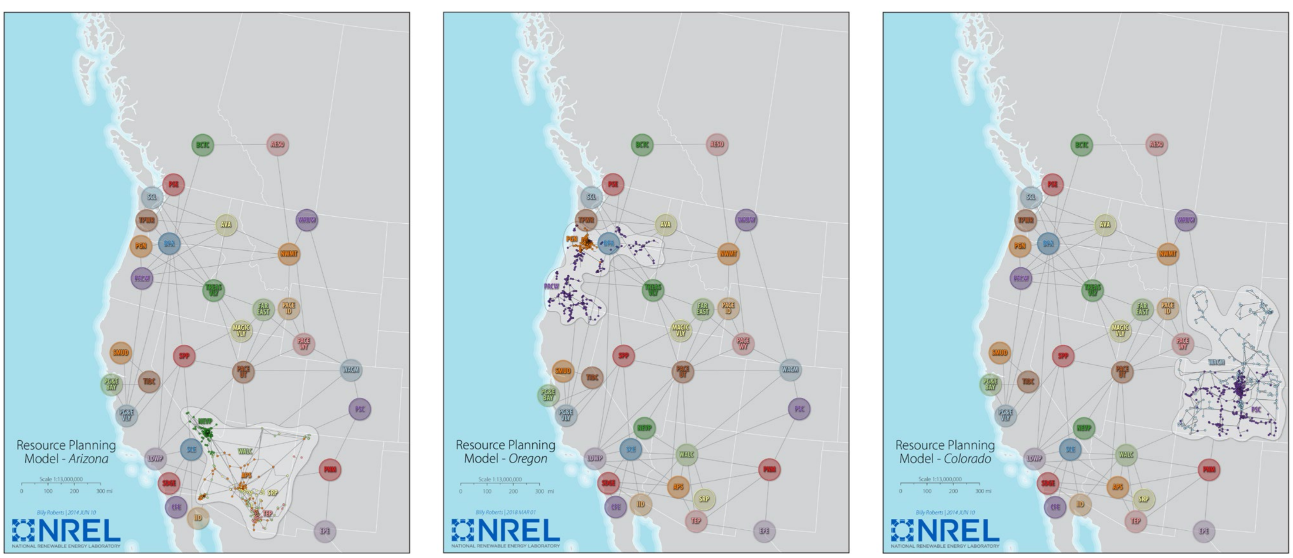

Figure 11. RPM focus models studied in this report: RPM-AZ, RPM-OR, and RPM-CO

[11] https://www.nrel.gov/analysis/models-rpm.html

RPM includes additional spatial layers to represent renewable resources. The models used here include 53–85 solar and 65–106 wind resource areas in the Western Interconnection to describe the location-specific resource potential in terms of developable area after accounting for land use exclusions,[12] performance in terms of wind and solar generators' annual and hourly capacity factors, and grid interconnection distances. Additionally, distributed PV is added exogenously based on projections from the Distributed Generation Market Demand Model (Sigrin et al. 2016). Resource regions are defined for each RPM focus model, with a greater density of resource regions being placed within the focus region than within the remainder of the interconnection, which ensures the region of interest is represented with high spatial resolution.

Figure 12. Western U.S. NERC subregions used for RPM planning reserve regions

This figure from the North American Electric Reliability Corporation's website (NERC 2018) is the property of the North American Electric Reliability Corporation and is available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2015_Summer_Reliability_Assessment.pdf. This content may not be reproduced in whole or any part without the prior express written permission of the North American Electric Reliability Corporation.

As load grows and generators retire, RPM requires additional capacity to ensure reliable operation of the system during peak conditions via a planning reserve constraint of an average of 16%. This constraint is applied to the five North American Electric Reliability Corporation (NERC) subregions of the Western Interconnection (WI) (Figure 12), including California/Mexico (CAMX), Northwest Power Pool Canada (NWPP-CA), Northwest Power Pool United States (NWPP-US), Rocky Mountain Reserve Group (RMRG), and Southwest Reserve Sharing Group (SRSG). Within the model, these planning reserve regions are required to meet or exceed the reserve margins recommended by NERC (2018). Within each NERC subregion, the capacity value of variable renewables and storage technologies is computed by methods described in Hale et al. (2016).

RPM makes investment decisions based on several assumptions. We include the federal renewable energy investment tax credit and production tax credit and the step-down of those policies, state renewable portfolio standards (RPS) as of 2017, and California's storage mandate, but not existing demand response programs, local incentives or California's carbon cap and trade program. Cost data for new natural gas-fired and wind capacity are consistent with those found in NREL's 2018 Annual Technology Baseline (ATB) mid case (NREL 2018). The ATB mid and low-price trajectories are used for solar technologies, particularly utility-scale PV and battery energy storage. Fuel prices are from the Energy Information Administration's Annual Energy Outlook 2018 Reference and High Oil and Gas Resource and Technology scenarios (EIA 2018).

To study the planning and operational impacts of high solar penetrations, we designed a set of scenarios to reach high levels of solar PV generation (Figure 13) and applied them to each focus model. The initial

[12] For example, we assume renewable generators cannot be placed on land that is too urban, wet, or steep, and that they cannot be placed in national parks, for example.

scenario is a reference case with midline gas price and technology costs, current policy requirements and midline distributed PV assumptions. This scenario is then perturbed to apply an increased RPS either only in the focus region (the Focus Goal scenario) or across the entire interconnection (the National Goal scenario). To favor high PV penetrations more than high wind penetrations, the National Goal scenario includes the assumption of low PV cost trajectories on the utility and customer (distributed PV) sides. To round out our scenario framework, we include two National Goal sensitivities: one with low battery energy storage costs (to potentially support additional PV deployment) and one with low natural gas prices (to reflect current trends in generation fleet composition in addition to fuel prices).

In all the non-reference scenarios, the RPS per state was formed artificially by leveraging the results of the 2017 NREL Standard Scenarios' National 80% RPS case (Cole et al. 2017). That is, an RPS was defined by specifying that each state should match the results seen in the Renewable Energy Deployment System (ReEDS) modeling for that scenario, assuming all hydro generation counts toward meeting the goal,[13] in addition to the more univocally designated renewable energy technologies (wind, solar PV, concentrating solar power, geothermal, and biomass). Similarly, adoption of distributed PV is specified using dGen results from the 2017 NREL Standard Scenarios; the National 80% RPS results are used for the Focus Goal scenario and Low PV Cost results for the National Goal scenarios. The resulting trajectory reaches fairly high RPS requirements across the Western Interconnection by 2035, but with a good deal of regional variation. For example, Arizona has a relatively low requirement (50%) by 2034, whereas the 2034 requirements for Idaho, Montana, Oregon and Wyoming are over 95%. This high variability in requirement is a result of national-scale least-cost modeling out to 2050 that prioritizes state-level results and considers investment decisions in a wide variety of technologies (see greater description of the ReEDS model in Cole et al. [2017]). In contrast, the RPM modeling prioritizes balancing authorities over states and only allows investments in a subset of technologies that might be of interest in a high-renewables future. Because the primary purpose of this report and broader study is to investigate reliability and planning challenges that might arise in high-PV systems, we prioritized creation of high-PV systems over highly plausible system build-outs. The results that follow should be interpreted in that light. That is, we are not suggesting that the particular PV penetrations modeled are appropriate for the model regions in any particular time period or perhaps ever; but the range of systems is constructed to provide insight into the range of possibilities, including some extremes.

[13] Because the goals are based on modeling outputs, we do not allow REC trading in the model for these scenarios.

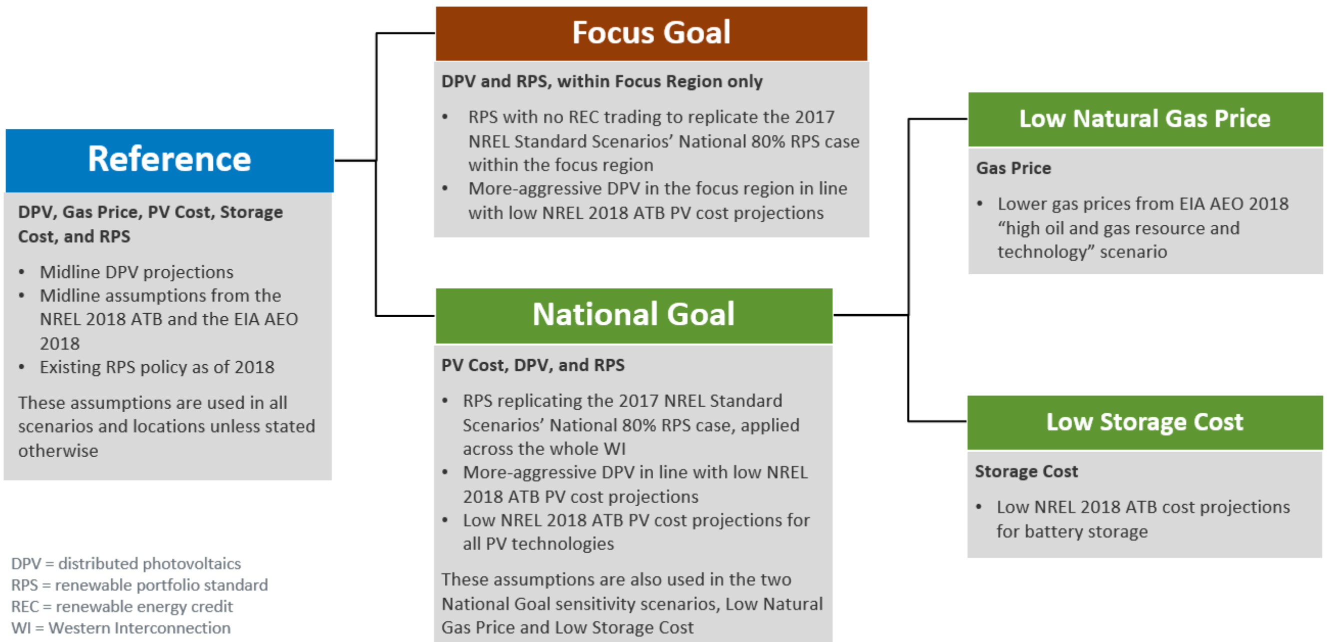

Figure 13. High PV penetration pathways

These scenarios led to increased solar deployment in all focus regions, from 19% to 77% PV within the focus region, and up to 33% PV across the entire Western Interconnection (Table 5). This report focuses on the two scenarios bolded in Table 5: the Reference case and the National Goal case. Figure 14 shows the final installed capacity for the Reference and National Goal scenarios for all focus regions. In all regions, the National Goal case has substantially more capacity (particularly PV and Battery storage), driven by the need to meet the high national RPS. More information on the RPM modeling and scenario results is available in Cowiestoll and Hale (2020).

Table 5. PV Penetration (%) in 2035 for All Scenarios and Focus Regions

	RPM-AZ				RPM-CO				RPM-OR			
	DPV		All PV		DPV		All PV		DPV		All PV	
	Focus	WI	Focus	WI	Focus	WI	Focus	WI	Focus	WI	Focus	WI
Reference	**5.8**	**3.2**	**30.1**	**15.5**	**2.0**	**3.2**	**11.5**	**13.7**	**1.3**	**3.2**	**10.4**	**15.0**
Focus Goal	7.5	3.4	49.7	19.1	3.5	3.3	24.1	14.6	1.4	3.2	75.4	17.3
National Goal	**7.2**	**3.7**	**48.1**	**30.8**	**3.8**	**3.7**	**18.7**	**25.0**	**2.0**	**3.7**	**75.6**	**27.2**
National + Storage	7.6	3.7	49.9	32.8	3.9	3.7	32.8	30.6	2.0	3.7	77.3	32.5
National + Gas	7.2	3.7	49.1	31.6	3.7	3.7	19.5	25.6	2.0	3.7	73.2	27.3

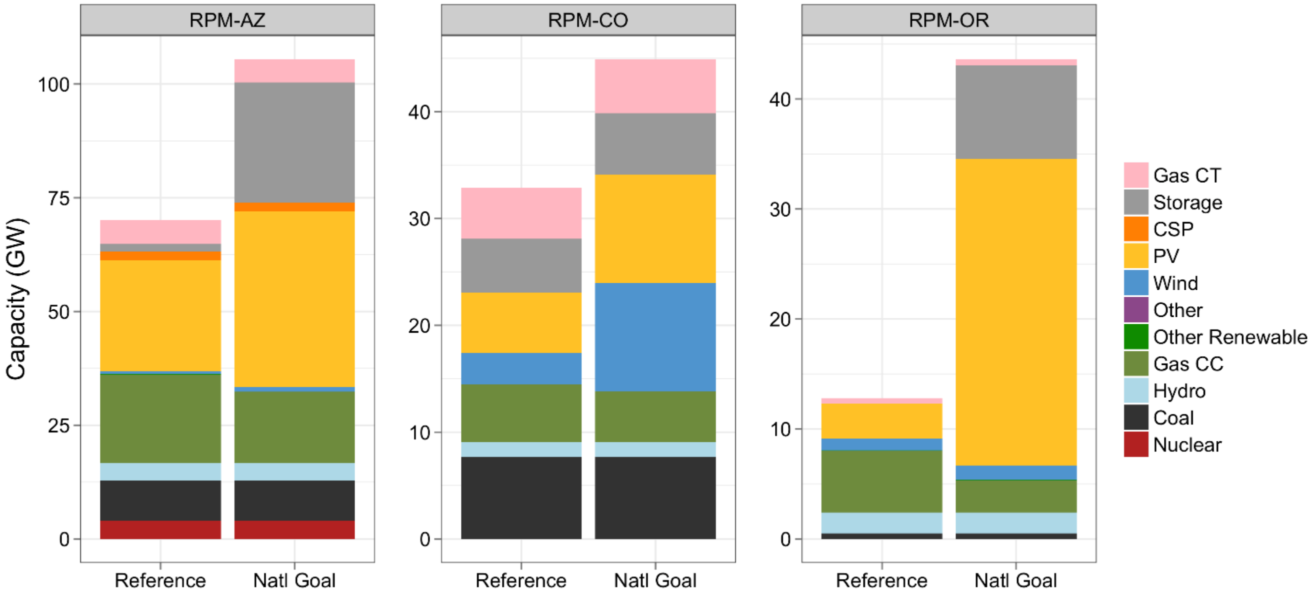

Figure 14. The 2035 capacity as determined by RPM for three focus regions in the WI under two scenarios, a Reference case and a National Goal case with high renewable targets (note the different y-axis scales)

As a planning tool, RPM does not conduct full chronological hourly dispatch and commitment. So, to expand on the results from RPM, we export the build-outs determined by RPM into a commercial production cost model (*PLEXOS Integrated Energy Model* version 7.400 R02 x64 Edition 2018). PLEXOS conducts an annual, chronological unit commitment and economic dispatch at hourly resolution for all scenarios presented above. We do a full generator-level dispatch for the entire Western Interconnection, with additional transmission representation in the focus region.[14] We then use the flexibility inventory framework presented in Section 3 to analyze any flexibility issues or challenges associated with the RPM scenarios.

We compare the two scenarios with the highest and lowest PV penetrations for the out-year of 2035: the Reference and the National Goal cases.[15] In all cases, quantifying the flexibility of the system is complicated by the fact that each focus region is a highly interconnected part of the whole Western Interconnection. In general, one focus region can integrate a large amount of variable renewable energy by heavily leaning on its neighbors to turn down its own generation and absorb (in this case) solar energy during the day.[16] Each balancing authority is limited in overall transfer capacity when trading with its neighbors, and hurdle rates of $2-10/MWh are applied on all transacted energy to represent friction in the ability to trade power, as well as real costs in the transactions. The Western Interconnection is large—encompassing thousands of generators across half of a continent. Therefore, there is much inherent flexibility across the entire interconnection, but that flexibility may or may not be

[14] We model full nodal representation within the focus region and balancing authority-level or zonal transmission representation outside of the focus region.
[15] Although the low-cost storage variant of the National Goal + Storage scenario has higher PV penetration, it is less interesting from a flexibility perspective due to the flexibility of the storage.
[16] The ability to share flexibility with neighboring regions has been called "exportable flexibility" and is discussed in Makarov et al. 2009.

available to each individual focus region. Therefore, we analyze the flexibility contained in each focus region, as well as the limitations of the focus region interacting with the larger interconnection.

3.1 Focus Region 1: RPM-OR

As discussed earlier in this section, we consider three different focus regions, with different regional generation, load, and resource characteristics. RPM-OR (which, as mentioned previously, includes the balancing authority areas of PACW and PGN) may not be typically thought of as a high solar resource region, especially during the cloudy winter months, but sees substantial PV buildout in the National Goal scenario due to the high regional requirement for renewable energy (see previous section). Another interesting aspect of RPM-OR is its load shape. Unlike much of the Western United States, RPM-OR has a winter-peaking system. The climate is less warm than the Southwest in the summer, meaning the cooling peak is less substantial in the summer, so the winter peak is driven by heating and lighting. The seasonal variation in load is much smaller than other regions. Figure 15 illustrates these trends for the 2035 Reference and National Goal cases by showing average diurnal plots for each of the four seasons. The load curve does not change much between the two scenarios (although it does change a little, as the National Goal case has more storage, which increases load). A dramatic change in variable generation potential between the two cases is due to the increasing presence of solar PV.

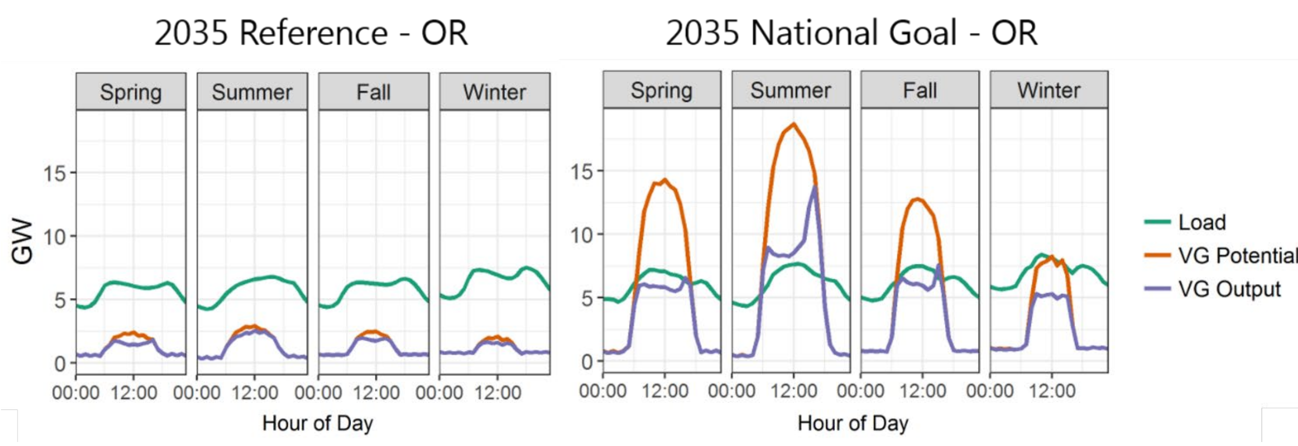

Figure 15. Average daily load profile and VG generation for each of the four seasons in the RPM-OR focus region for two scenarios

Figure 16 shows the average diurnal net load of the same two scenarios. Solar somewhat influences the shape of the net load in the Reference case and transforms the net load curve for the National Goal case, which even exhibits negative net load during midday in most seasons, indicating the focus region is exporting solar energy in the middle of the day and curtailing PV substantially—the difference between the VG Potential line and the VG Output line in Figure 15.

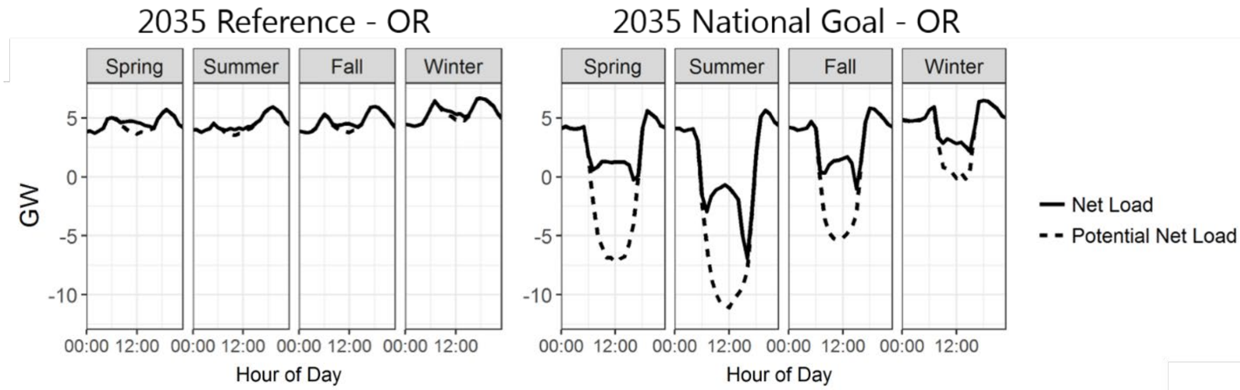

Figure 16. Average daily net load profile for the two scenarios in the RPM-OR focus region

The difference between the net load and potential net load lines indicates renewable energy curtailment.[17]

Figure 15 and Figure 16 (above) indicate the characteristics of a solar-heavy system (a low net load in midday, and large down and up ramps during sunrise and sunset respectively). Figure 17 illustrates the maximum annual net load ramp for the two scenarios. We see that the maximum ramp up and ramp downs are much higher in the National Goal case, and that the maximum 1-hour net load ramp is greater than 10 gigawatts on a less than 10 gigawatts peaking system. We use our flexibility tool to determine how the system meets these large ramps, by quantifying the flexibility for these two scenarios.

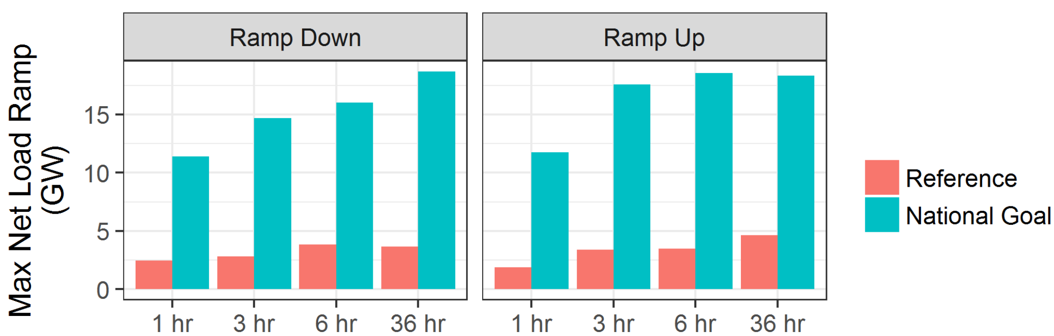

Figure 17. Maximum annual net load ramps in the RPM-OR focus region for two scenarios

Generally, we find no flexibility shortages as it relates to ramping in these two scenarios. Although "flexibility" as we define it here is not included in the objective function, a flexibility shortage may manifest itself as unserved energy, unserved reserves, or transmission limit penalties. As indicated in another report in this series (Stephen, Hale, and Stoll 2020), the capacity expansion tool (RPM) used to build these scenarios often results in overbuilt systems with plenty of capacity. Although capacity is not synonymous with flexible capacity, capacity helps ensure sufficient ramp to cope with the large swings in net load observed in these scenarios. Furthermore, we are not modeling the focus region in isolation, and the rest of the West sees lower PV generation than the focus region, meaning the rest of the system can help absorb excess PV during the day, and ramp up and down generation (and thus imports and exports) more easily. As Table 5 indicates, RPM-OR has substantially higher PV than the rest of the

[17] Figure 15 illustrates a substantial amount of PV curtailment. Some curtailment is likely to be expected at such high PV levels, but the amount seen here is high and hard to predict with existing capacity expansion models, such as the one used to derive these scenarios.

Western Interconnection in the National Goal scenario. The ability to rely on neighbors would be limited under higher PV penetration in surrounding regions.

Figure 18 illustrates the sources of one-hour flexibility for this focus region and indicates most of the region's flexibility comes from the ability to import and export from surrounding regions. A great deal of the flexibility indicated on this plot as imports is actually the flexibility of hydropower plants in neighboring balancing authorities, such as the Bonneville Power Administration. We see flexibility coming from the gas combined-cycle (gas CC) fleet, and from the storage fleet in the National Goal case. Note that in an average hour, the total sum of flexibility is considerably less than the one-hour maximum net load ramp illustrated in Figure 17. Figure 18 represents an average over all hours, and the flexibility profile for a "non-average" (or maximum ramp) hour might look considerably different. For instance, Figure 19 illustrates the maximum one-hour net load ramp up and down in the National Goal cases. In both the ramp up and ramp down cases, the vast majority of ramping is being supplied by imports, with a small amount coming from the storage fleet.

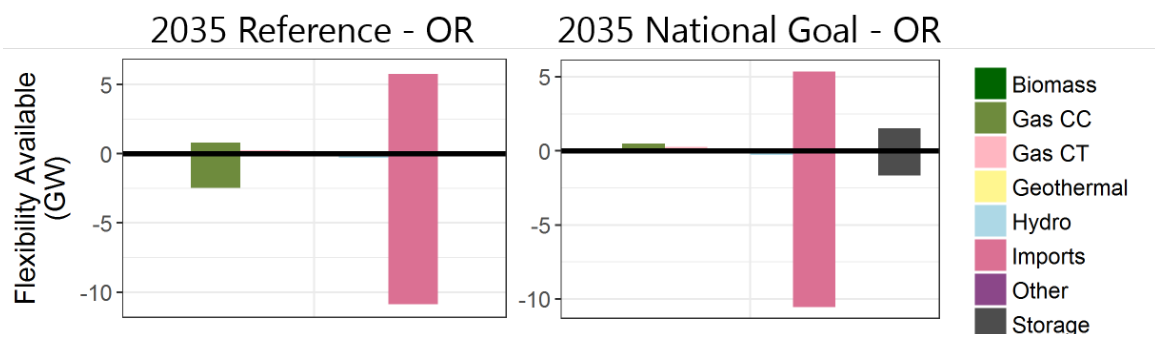

Figure 18. Average hourly flexibility available from various sources in the RPM-OR focus region

A recurring theme of this analysis (to be seen in the other focus regions as well) is that in an interconnected system, a lot of flexibility is gained from neighboring regions. Since RPM-OR is located in the Pacific Northwest of the U.S., many of the neighboring regions are dominated by hydropower. Although not all hydropower plants are flexible, many dispatchable hydro plants have a substantial amount of flexibility and are likely helping to moderate the impacts of PV deployment with their ability to turn down or off in the middle of the day. Additionally, we emphasize that PV deployment in RPM-OR outpaced its neighbors in this scenario (as shown in Table 5), which means there is still an external demand for excess PV energy during the day. This may not be the case in a future scenario with more PV deployment in neighboring regions in which the flexibility identified here may not be sufficient. Further, although we do capture nodal transmission constraints within the focus region, we have a simplified representation of transmission outside the focus region. Those interzonal connections are subject to flow limits, but further work is required to determine whether this simplified representation is sufficient.

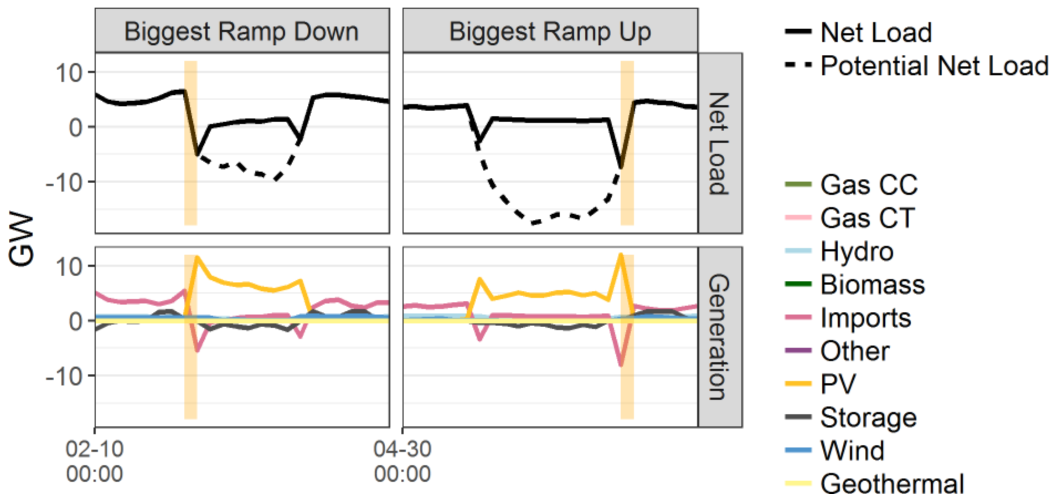

Figure 19. Maximum ramp up and down hours for the RPM-OR focus region in the 2035 National Goal scenario

The difference between the net load and potential net load lines indicates renewable energy curtailment.

3.2 Focus Region 2: RPM-CO

We next examine the RPM-CO focus region, which is composed of the WACM and PSC balancing authorities. This system has a typical summer-peaking load shape, but unlike the other two focus regions, it sees substantial growth in wind generation in addition to PV in the National Goal scenarios. Figure 20 shows the load and variable generation profiles for the Reference and National Goal cases. Although PV increases slightly between the two, much of the growth in variable generation is due to wind, which has a different generation profile (generally greater during the night, lowest in the warm summer months). Figure 21 shows the resulting net load curve, which indicates that the "potential" (pre-curtailment) net load drops below zero in the non-summer months for the National Goal case, but the actual net load on average stays above zero.

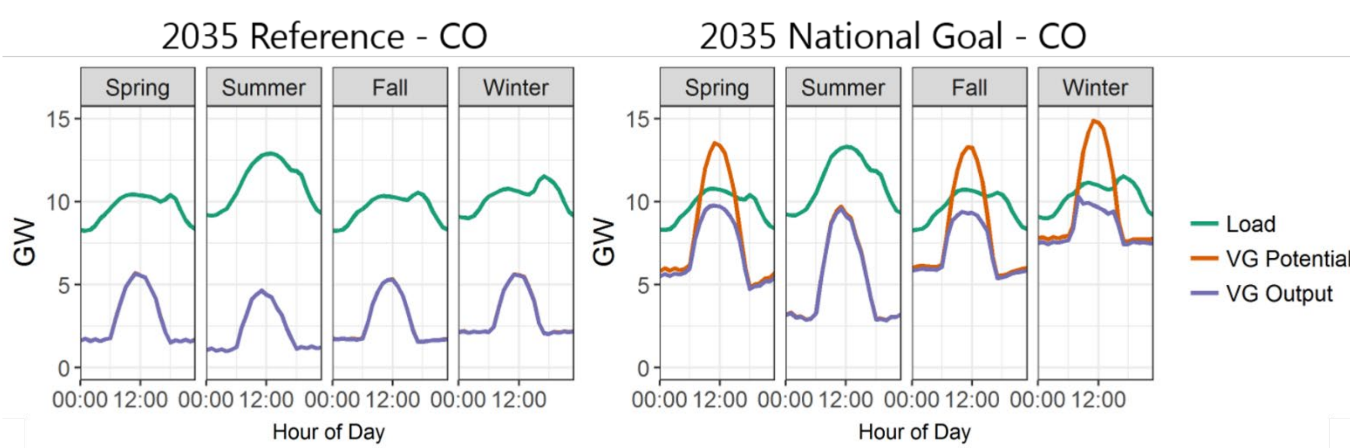

Figure 20. Average daily load profile and VG generation for each of the four seasons in the RPM-CO focus region for two scenarios

Figure 22 shows RPM-CO focus region's maximum annual net load ramp for the four time frames. As in the RPM-OR focus region, the maximum ramp increases in the National Goal case. However, the maximum ramp in RPM-CO does not increase by as large a magnitude as in RPM-OR, because much of the added renewable energy is wind, which offers different ramping profiles. Although the interactions between solar and wind can be complicated, in general, wind energy may actually be ramping up as solar generation is ramping down, and vice versa, which is why the addition of both resources has a less profound impact on the net load ramps in the RPM-CO system.

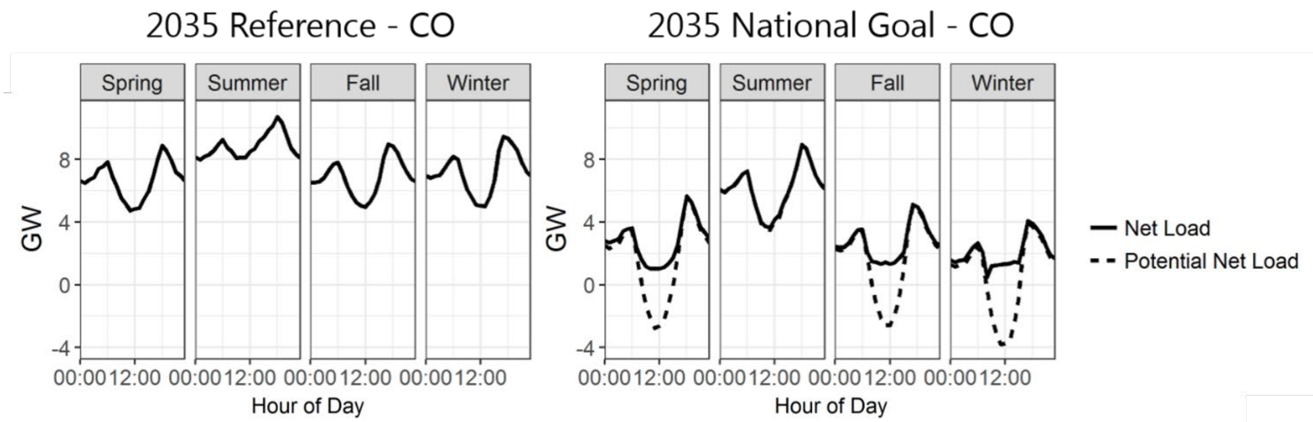

Figure 21. Average daily net load profile in RPM-CO focus region for the two scenarios

The difference between the net load and potential net load lines indicates renewable energy curtailment.

Much like with the RPM-OR focus region, we do not see any signs of insufficient flexibility as would be indicated by various system penalties. Obviously, we do see a substantial amount of curtailment, which reduces the amount of flexibility required. The RPM-CO focus region also has different flexibility sources, as shown in Figure 23 for the two scenarios. Although RPM-CO does have a substantial amount of flexibility coming from imports, the thermal fleet contributes in total roughly the same amount. Relative to the RPM-OR focus region, RPM-CO is slightly less interconnected with the rest of the system and relies on its own thermal fleet for more flexibility. This is indicated in Figure 24, which shows the maximum up and down net load one-hour ramp for the 2035 National Goal case. The largest ramp down in net load is actually being caused by a ramp *up* in wind generation, and it is met largely by reducing imports. The biggest ramp up is caused by a reduction in both solar PV and wind energy, which is met by imports, coal, and some gas combined-cycle (CC) generation.

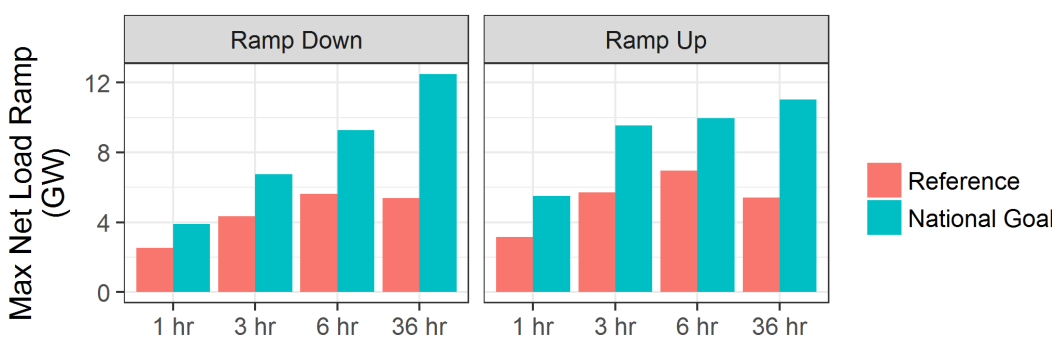

Figure 22. Annual maximum net load ramps in the RPM-CO focus region for two scenarios

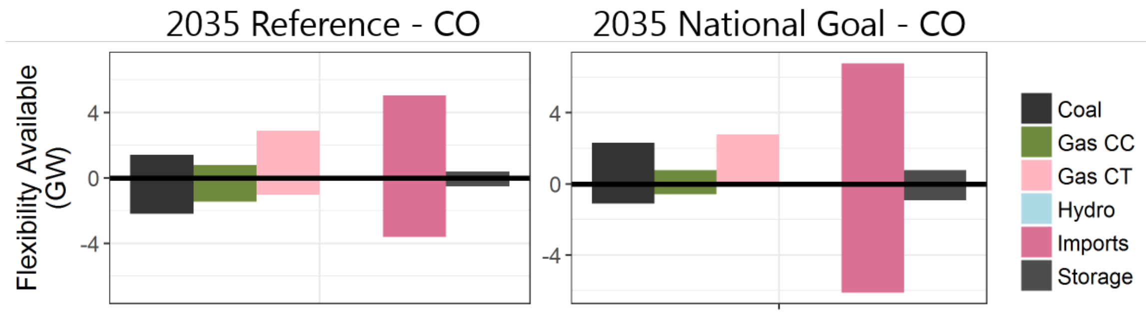

Figure 23. Average hourly flexibility available from various sources in the RPM-CO focus region

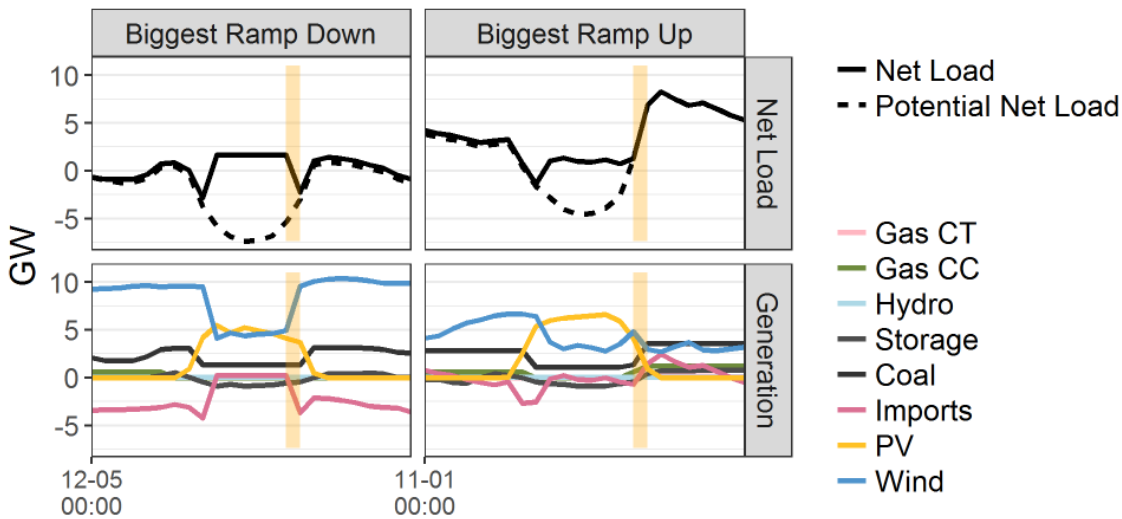

Figure 24. Maximum ramp up and down hours for the RPM-CO focus region in the 2035 National Goal scenario

The difference between the net load and potential net load lines indicates renewable energy curtailment.

3.3 Focus Region 3: RPM-AZ

Finally, we examine the RPM-AZ focus region, which includes the balancing authorities of APS, SRP, WALC, TEP, and NEVP. By total load, this region is the largest of the three and most of the state has a desert climate. This means the load shape (Figure 25) is driven by cooling load and is much greater in the summer (especially late afternoons and evenings), even though the solar resource (VG Potential on Figure 25) is fairly consistent year-round. Although the VG Potential increases between the Reference and National Goal cases, the actual VG output does not change much, meaning the additional PV capacity is largely being curtailed. This is further illustrated in the net load curve (Figure 26), in which the solid line looks similar between the two scenarios, although the dotted line dips much lower each day to indicate unused PV energy. Likewise, the maximum ramps in Figure 27 are very similar between the two scenarios.

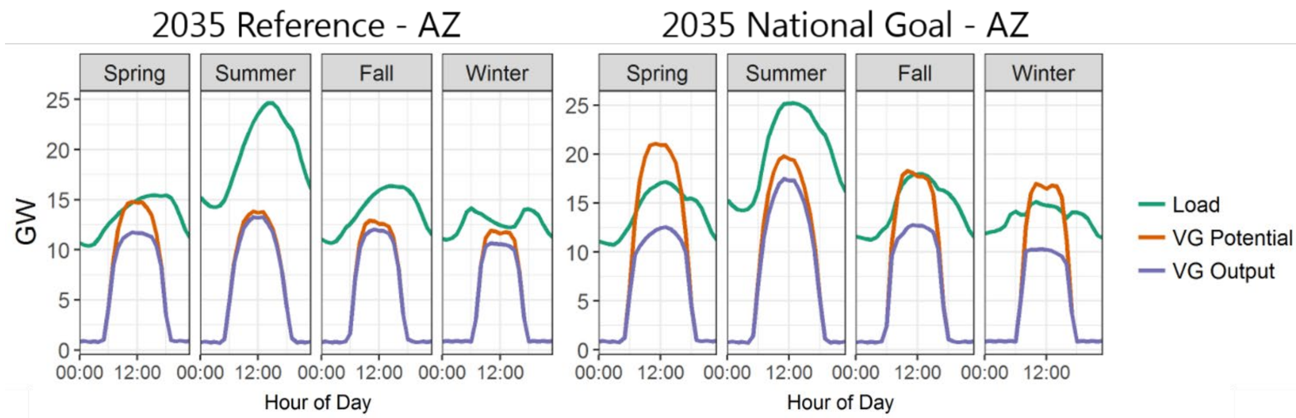

Figure 25. Average daily load profile and VG generation for each of the four seasons in the RPM-AZ focus region for two scenarios

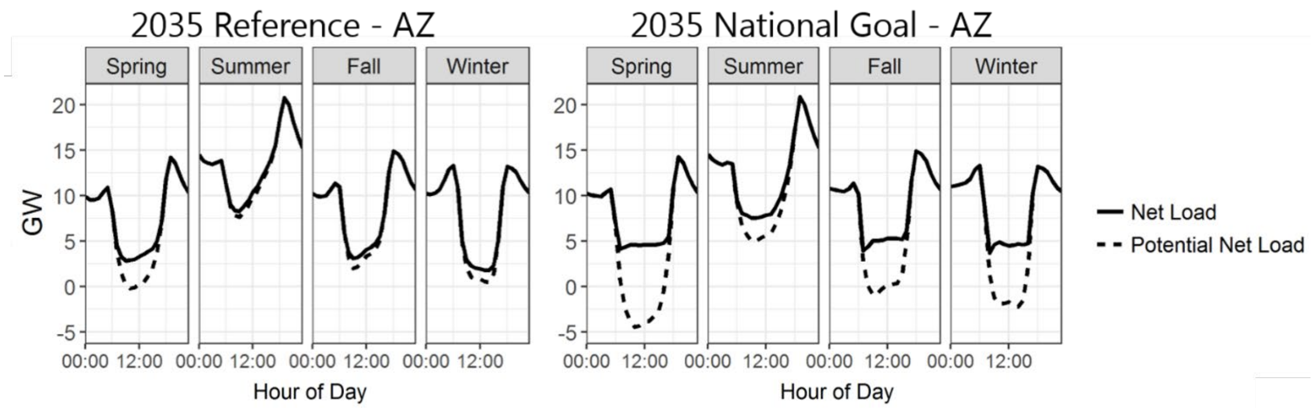

Figure 26. Average daily net load profile in the RPM-AZ focus region for the two scenarios

The difference between the net load and potential net load lines indicates RE curtailment.

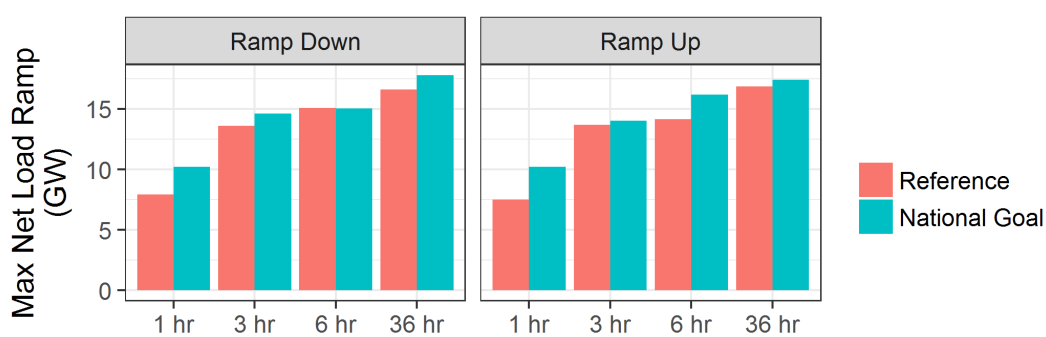

Figure 27. Annual maximum net load ramps in the RPM-AZ focus region for two scenarios

The RPM-AZ focus region is unique for another reason—more of its flexibility actually comes from internal sources, rather than imports. As Figure 28 indicates, RPM-AZ still gets a fair amount of flexibility from imports, but a lot of flexibility comes from its gas CC fleet, with some coming from coal, other (mostly gas steam turbines), and storage. Figure 29 shows the timeseries representation of the maximum one-hour ramps in both directions, and indicates flexibility from imports, the coal fleet, gas CCs, and storage.

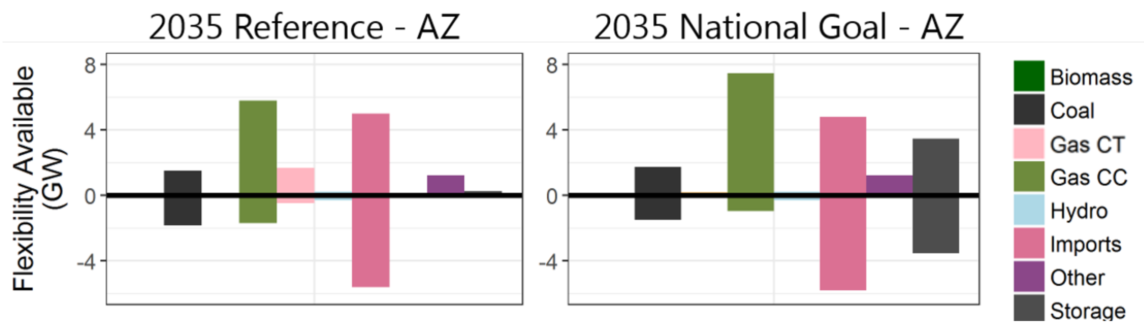

Figure 28. Average hourly flexibility available from various sources in the RPM-AZ focus region

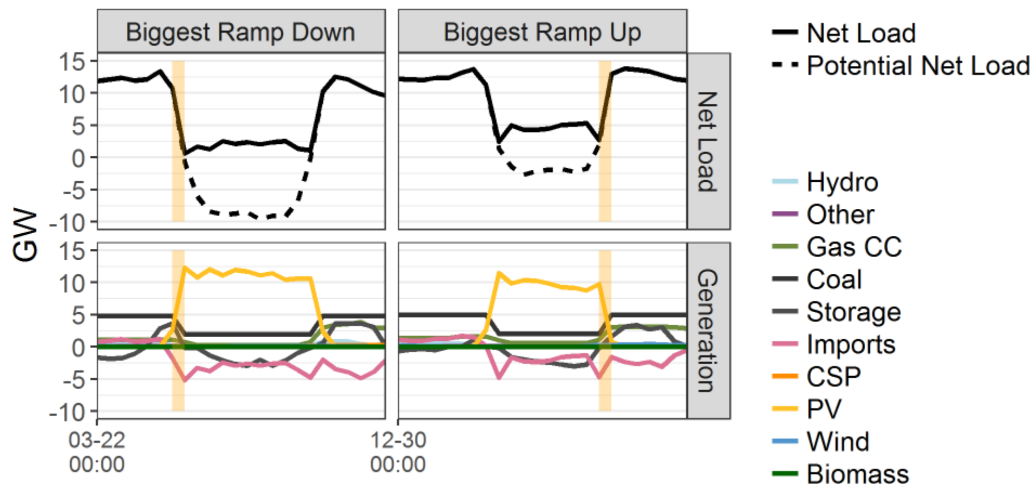

Figure 29. Maximum ramp up and down hours for the RPM-AZ focus region in the 2035 National Goal scenario

The difference between the net load and potential net load lines indicates renewable energy curtailment.

4 Conclusions

As penetrations of variable generation technologies such as wind and PV continue to increase across the United States, greater uncertainty and variability in the net load often lead to a concern about how power systems may adapt. However, there is inherent flexibility in power systems through the conventional generator fleet (under least-cost unit commitment and economic dispatch), unconventional generation sources (e.g., storage, demand response, and concentrating solar power-thermal energy storage), and imports and exports with neighbors. We create an open-source tool[18] to analyze the flexibility of the results of a specific commercial unit commitment and economic dispatch tool (PLEXOS), but the code can be applied generically as well. The tool assesses the flexibility *requirements* (or demand) of a system through a net load analysis. Then, the constraints and limitations of each generator is considered to determine the *availability* (or supply) of flexibility. Then, the supply and demand of flexibility are compared to gain a more complete picture of potential flexibility concerns.

We apply this open-source tool to high-penetration PV scenarios constructed for three regions in the Western United States (defined using three focus regions in the capacity expansion tool RPM: RPM-OR, RPM-CO, and RPM-AZ) and analyze the resulting system flexibility needs and supply. Generally, we find few flexibility concerns because the Western United States represents a large and interconnected power system with much inherent flexibility. In addition, the PV scenarios analyzed have significant overall generation capacity on the system, leaving plenty of capacity with the ability to ramp. We find that for each focus region, the impact of imports on meeting ramping needs is essential. This means the PV integration in each focus region impacts the entire rest of the system. Each system has different dominant sources of flexibility, and the conventional generator fleet (especially coal and gas combined-cycle technology), as well as less conventional sources such as storage, are all identified as important sources of flexibility.

Although the tool presented here provides useful metrics and analysis, it also leaves the door open for future expansion of capabilities. For instance, the tool would benefit from a more robust inclusion of energy-limited sources of flexibility, which may be limited on different time frames (e.g., hydropower, pumped hydro storage, batteries, demand response, and concentrating solar power). We also look to include uncertainty in the tool (i.e., incorrect forecasts for variable generation production), because the tool currently assesses only real-time profiles for PV and wind.

[18] http://github.com/NREL/MAGMA

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