Grid Modernization: Metrics Analysis (GMLC1.1) – Flexibility

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Summary

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Flexibility

The ability to respond to future uncertainties that may stress the system in the short term and require the system to adapt over the long term.

These two temporal dimensions translate to different flexibility perspectives: 1) an operational viewpoint that relies on the agility of a static electrical network to adjust to known or unforeseen changes, as in load conditions or sharp ramps due to error in renewable generation forecasts; and 2) a planning viewpoint that relies on changing the electrical network to respond to new regulatory and policy changes as well as to technological breakthroughs (ideally without incurring stranded assets). This project focused on the operational viewpoint.

The Grid Modernization Laboratory Consortium (GMLC) Metric Team worked with data from the California Independent System Operator and the Electricity Reliability Council of Texas to develop and demonstrate both new lagging and new leading metrics that measure the flexibility of the bulk power system in accommodating high penetrations of variable sources of renewable electricity.

S.1. Motivation

Increased variability and uncertainty resulting from growing shares of variable renewable generation, such as wind and solar power, are increasing the need for flexibility in grid planning and operations. In the past, static measures of (and metrics for) generation resource adequacy were generally sufficient to ensure reliability. Going forward, power systems with larger shares of wind and solar generation will also require supplementary sources of flexible generation (and load) to accommodate continuously varying and sometimes large swings in the output from wind and solar generation.[1] The goal of these flexible sources is to balance load and generation by ensuring the "net load," or difference between total system load and the output from wind and solar generation, is always met.

Static measures of generation adequacy are not capable of capturing the requirements for these flexible sources of generation. For example, in the past, a traditional loss-of-load probability analysis could be used to develop a simple metric like a planning reserve margin that would be sufficient to ensure reliability. Such a planning reserve margin alone is not sufficient to ensure adequate reliability due to the increased variability and uncertainty associated with operating a power system that has significant penetration of wind and solar generation. As a result, there is growing recognition that traditional assessments of reliability need to be augmented with additional measures that adequately capture these issues related to flexibility.

[1] See, for example, Edmunds, Thomas, Omar Alzaabi, and Andrew Mills. 2017b. *Flexibility Metrics to Support Grid Planning and Operations*. LLNL-CONF-738350, Siebel Energy Institute Future Markets Workshop, Washington, DC, which was prepared as part of this GMLC project.

S.2. Outcomes/Impact

The GMLC team developed new lagging and leading metrics to measure aspects of operating power systems with high penetrations of wind and solar generation.

The team developed new lagging metrics using historical data provided by California Independent System Operator (CAISO) and ERCOT and new lagging metrics for flexibility using production cost simulations of the California grid. CAISO and ERCOT were selected because both grid operators have considerable experience operating power systems with high penetrations of wind and solar generation and hence have a wealth of operating data from which new lagging flexibility metrics could be demonstrated.

The lagging metrics focus on three aspects of the flexibility required to operate a power system reliably with high penetrations of wind and solar generation: 1) minimizing over-generation by traditional generation sources when the output from wind and solar is high; 2) ramping traditional generation quickly and for extended periods during the late afternoon when solar generation decreases and system load increases; and 3) dealing with the inherent uncertainty involved in forecasting the output from wind and solar generation.

The team identified measures that express the relevant dimension of each aspect of flexibility and then posited indicators or metrics of inflexibility for each dimension. See Table S.1.

Table S.1. Taxonomy of Lagging Flexibility Metrics

Dimension of Flexibility	Flexibility Demand	Indicator of Inflexibility
Over-generation	Ratio of peak to minimum	Renewable curtailment, negative prices
Ramping	Ramp rates of net demand	Price spikes, out-of-market actions
Uncertainty	Net demand forecast errors	Real-time price premium, cost of forecast errors

Over-generation is a particular concern for flexibility during periods when net demand is at a minimum. As a last resort, grid operators will actually curtail the output from wind or solar generation when market-based options for balancing load and generation have been exhausted. Figure S.1 shows the times of day and year and the amounts of curtailed renewable energy for CAISO over a five-year period. The figure indicates that curtailments have been increasing over time, particularly around the noon hour when solar generation is at a maximum.

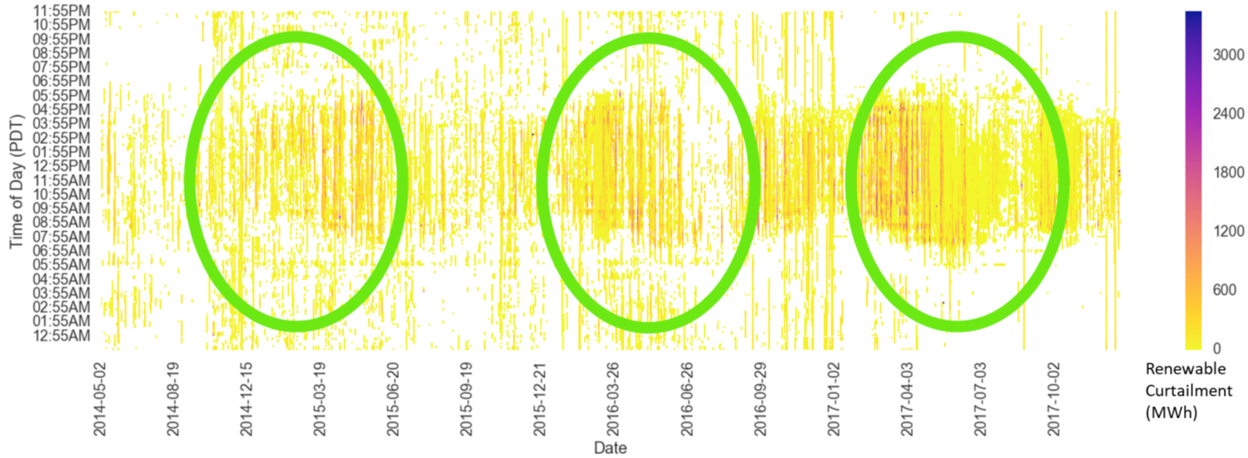

Figure S.1. CAISO Renewable Curtailment (MWh)

The team also developed new leading metrics of flexibility and demonstrated them using production cost simulations of the California grid.[2] Figure S.2 shows an example of the application of a production cost model to evaluate system flexibility using three different flexibility metrics—renewable curtailment, operational savings, and renewable economic carrying capacity. The example is drawn from a study of the California grid under increased penetration of solar photovoltaics (PV) (Denholm et al. 2016). Four flexibility measures were introduced relative to the base case: 1) added 1,290 MW of new storage, roughly following the California storage mandate; 2) changed the instantaneous variable generation (VG) penetration limit from 60% to 80%; 3) removed a 25% local-generation requirement; and 4) allowed curtailed VG to provide upward regulation, contingency, and flexibility reserves.

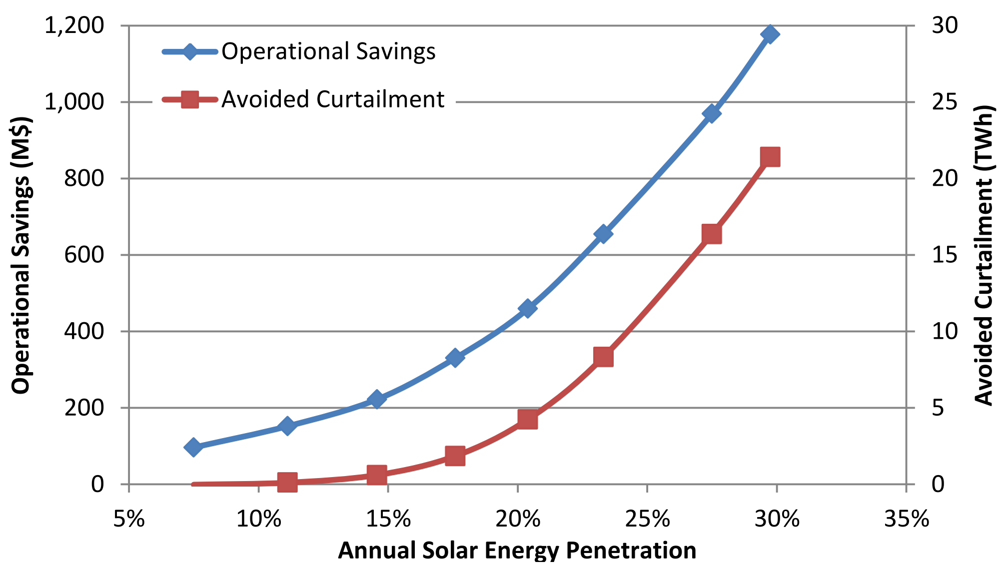

Figure S.2. Operational Savings and Curtailment Reduction Associated with Added Flexibility

Figure S.2 shows the operational savings as a function of PV penetration for the increased operational flexibility case, as well as avoided PV generation curtailment. The base case represents a "business-as-

[2] A production cost model simulates a least-cost unit commitment and dispatch over a period of time to establish which resources—generators, storage, or demand response—are required to be online to meet the electricity demand and supply reserves for operational reliability, and to satisfy other system constraints.

usual" scenario with traditional operating practices prior to 2016, including multiple restrictions on the flexibility of thermal power plants, interaction with neighboring regions, and provision of reserve services from VG. The increased operational flexibility case represents changes that are under way and will likely be implemented by 2020 (CPUC 2015). These changes include allowing greater use of VG for provision of reserves and reliability services, as well as the addition of over 1,000 MW of new storage in response to the California storage mandate (Eichman et al. 2015). Note that for this study several different flexibility metrics are changed at the same time. Production cost models could also be configured to investigate the impact of making each of the changes in isolation.

Acknowledgments

The analysis team would like to thank the California Independent System Operator and the Electric Reliability Council of Texas for their advice and data resources.

Acronyms and Abbreviations

CAISO	California Independent System Operator
DOE	U.S. Department of Energy
ECC	economic carrying capacity
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas, Inc.
FERC	Federal Energy Regulatory Commission
GMLC	Grid Modernization Laboratory Consortium
GMLC1.1	Grid Modernization Laboratory Consortium Project Metrics Analysis
IRRE	Insufficient Ramping Resource Expectation
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
LOLE	loss-of-load expectations
LOLP	loss-of-load probability
MW	megawatt(s)
NERC	North American Electric Reliability Corporation
PCM	Production Cost Model
PG&E	Pacific Gas and Electric Company
TVA	Tennessee Valley Authority
VG	variable generation
WECC	Western Electricity Coordinating Council

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1.0 Introduction

1.1 Project Background and Motivation

The U.S. Department of Energy's (DOE's) 2015 Grid Modernization Initiative Multi-Year Program Plan (MYPP) states that as the US electric grid transitions to a modernized electric infrastructure, policy makers, regulators, grid planners, and operators must seek balance among six overarching attributes (DOE 2015a): (1) reliability, (2) resilience, (3) flexibility, (4) sustainability, (5) affordability, and (6) security. Some attributes have matured and are already clearly defined with a set of metrics (e.g., reliability), while others are emerging and less sharply defined (e.g., resilience). To provide more clarity to the definition and use of the attributes, the DOE is funding an effort that will evaluate the current set of metrics, develop new metrics where appropriate, or enhance existing metrics to provide a richer set of descriptors of how the US electric infrastructure evolves over time.

The DOE engaged nine National Laboratories to develop and test a set of enhanced and new metrics and associated methodologies through the Grid Modernization Laboratory Consortium (GMLC)'s Metrics Analysis project, generally referred to by its acronym GMLC1.1.

The project, started in April 2016, supports the mission of three DOE Offices—Office of Electricity Delivery and Energy Reliability, Office of Energy Efficiency and Renewable Energy, and Office of Energy Policy and Systems Analysis—by revealing and quantifying the current state of the nation's electric infrastructure and its evolution over time.

This report reflects the accomplishments of GMLC1.1 Year 1 activities.

1.2 Metric Categories Definitions

The MYPP uses the term attribute to describe the characteristics of the power grid. In this report, we use the term metric areas or metric categories. Metrics are physical measurements or economic measures that can be calculated Several metrics can be grouped into a metric category.

The six metric categories explored in this project are described in Table 1.1. The purpose of this table is to list commonly used definitions and indicate which aspects of the large breadth within a metric category this project addresses.

Table 1.1. Metrics Descriptions and Focus Areas

Metric Categories	Definitions	Focus Areas Under GMLC1.1
Reliability	Maintain the delivery of electric services to customers in the face of routine uncertainty in operating conditions. For utility distribution systems, measuring reliability focuses on interruption of the delivery of electricity in sufficient quantities and of sufficient quality to meet electricity users' needs for (or applications of) electricity. For the bulk power system, measuring reliability focuses separately on both the operational (current or near-term conditions) and planning (longer-term) time horizons.	We are developing new metrics of distribution reliability, which account for the economic cost of power interruptions to customers, with American Public Power Association. We are developing new metrics of bulk power system reliability for use in the North American Electric Reliability Corporation's Annual State of Reliability Report. We are demonstrating the use of probabilistic transmission planning metrics with Electric Reliability Council of Texas, Inc. and Idaho Power.
Resiliency	Can prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions, including the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents (Obama 2013).	We apply a consequence-based approach that defines a process using resilience goals to a set of defined hazards. This approach provides the information needed to prioritize investments for resilience improvements.
Flexibility	Respond to future uncertainties that may stress the system in the short term and require the system to adapt over the long term. Short-term flexibility to address operational and economic uncertainties that are likely to stress the system or affect costs. Long-term flexibility to adapt to economic variabilities and technological uncertainties that may alter the system.	We focus on flexibility of the bulk power system needed to accommodate the variability of net load, which is the load minus variable generation including high penetrations of variable resource renewables.
Sustainability	Provide electric services to customers minimizing negative impacts on humans and the natural environment.	We focus on environmental sustainability specifically in year 1, assessing metrics for greenhouse gas emissions from electricity generation.
Affordability	Provide electric services at a cost that does not exceed customers' willingness and ability to pay for those services (Taft and Becker-Dippman 2014).	We document established investment cost-effectiveness metrics and focus our research on emerging customer cost-burden metrics.
Security	Prevent external threats and malicious attacks from occurring and affecting system operation. Maintain and operate the system with limited reliance on supplies (primarily raw materials) from potentially unstable or hostile countries. Reduce the risk to critical infrastructure by physical means or defense cyber measures to intrusions, attacks, or the effects of natural or man-made disasters (Obama 2013).	We develop metrics to help utilities evaluate their physical security posture and inform decision-making and investment.

The metric categories are described in depth in the ensuing chapters of this report.

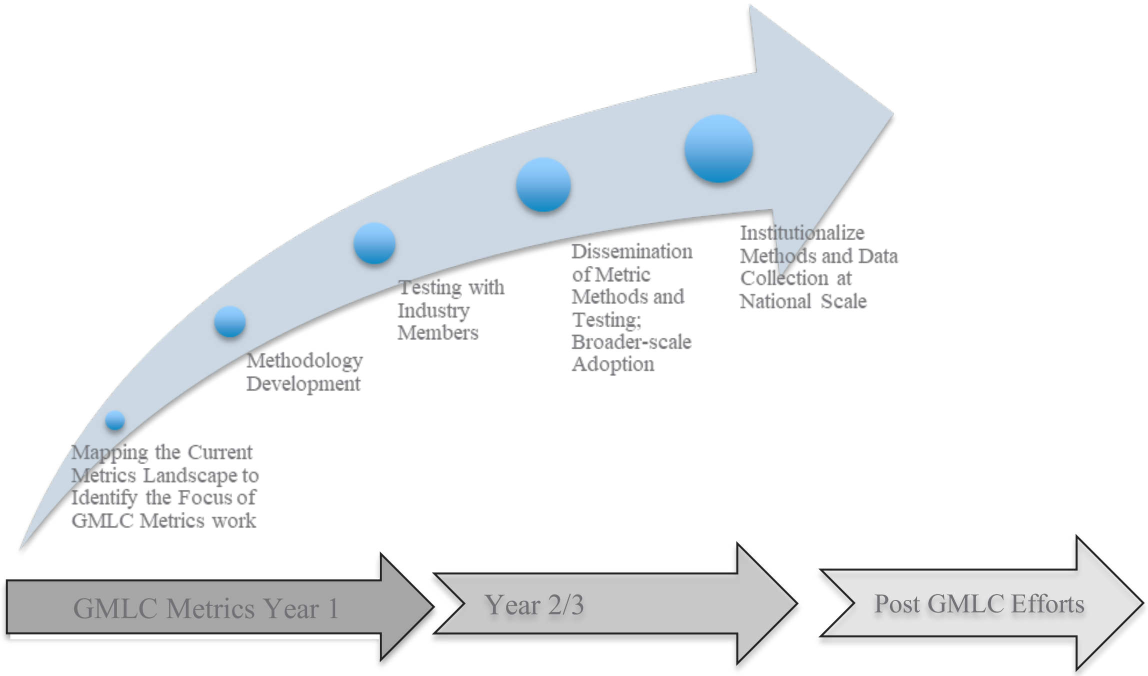

Figure 1.1. Time Line for GMLC1.1 Activities

Specific approaches to formalizing metrics varied across the six metrics category teams, depending on the maturity of metrics development and use in the area, the existence of publicly collected and disseminated sets of supporting data, and the presence of other organizations working in the space. The specific approaches included:

- Developing new methodologies and working with specific partners to pilot test the usefulness of these metrics with their data
- Collaborating with and leveraging related efforts of established national data providers or industry associations to explore and develop with them new ways of looking at their data
- Adapting methodologies originally developed for a specific stakeholder for broader application
- In emerging areas, working with a collection of system operators and utilities to carefully identify the existing measurement landscape and a longer-term research program to develop methodologies that could be effectively applied across jurisdictions.

Metrics are categorized by their ability to characterize: the electricity system's properties historically (*lagging* metrics); or the system's ability to respond to challenges in the future (*leading* metrics). Lagging metrics are backward-looking, or retrospective, where the impact of a collection of activities on a specific system can be assessed after their actual implementation. As such, they can be helpful aggregate indicators of progress being made in grid modernization. Leading metrics are forward-looking or prospective, where the future impact of an activity can be estimated prior to its actual completion or implementation on a system. As such, they can be used to inform decisions on infrastructure investments or policy interventions.

2.0 Approach

2.1 Problem Definition

Increased variability and uncertainty resulting from growing shares of variable renewable generation, such as wind and solar power, are increasing the need for flexibility in grid planning and operations. In the past, maintaining adequate capacity could ensure reliability. However, future power systems with larger shares of variable renewables must have capacity and demand sufficiently flexible to accommodate large swings in load net of wind and solar generation. The challenges are discussed in a 2017 survey paper presented at a Siebel Institute Workshop in 2016 (LLNL-CONF-338350).

The renewable integration challenge is illustrated by Figure 2.1, which shows historical and projected net loads in March in California under a 33% renewable portfolio goal in year 2020 (Loutan 2016). As indicated by the figure, solar generation depresses net load in the middle of the day, causing dispatchable generation to be turned down or shut off. A system without sufficient flexibility runs the risk of over-generation. As the sun sets in the evening, solar production falls off, requiring large ramp rates in generation from other sources to meet the evening peak. As indicated by the blue comment bubble in the figure, data from March 2015 indicate that evolution of the pattern is one year ahead of original forecasts. In addition to these multi-hour ramps in net load, system operators must also accommodate intra-hour volatility and imperfect forecasting of net load.

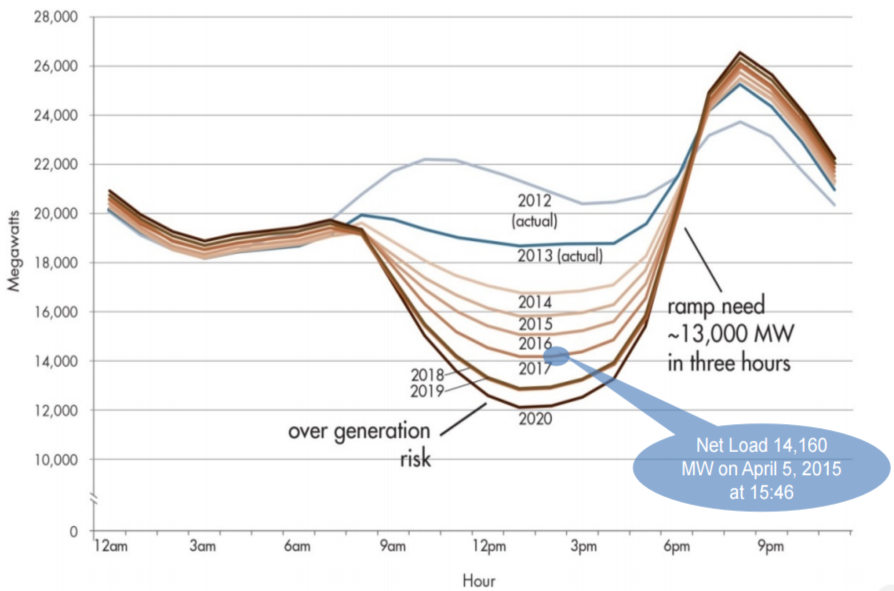

Figure 2.1. Net Load Profile in California in March (Duck Curve)

An update of the net load curves with historical data is shown in Figure 2.2, which displays the lowest March daytime net load for the years 2011 through 2016. A ramp up of 11,000 megawatts (MWs) in three hours was required to compensate for the drop in solar generation and increase in load during that time period. Although the California Independent System Operator (CAISO) has been able to accommodate ramp rates of this magnitude in the past, recent and projected retirements of flexible fossil fuel units may make this more difficult in the future. These challenges will become more severe as California pursues more aggressive renewable generation goals, including 50% renewable generation by the year 2030 (CA State Legislature 2018).

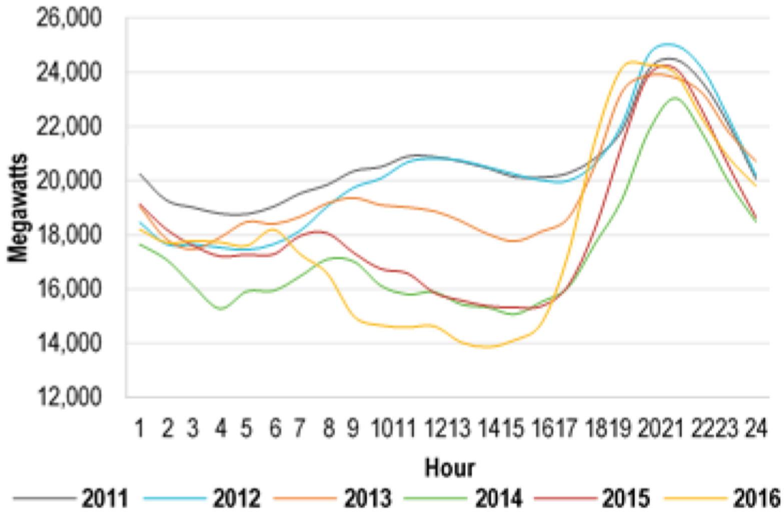

Figure 2.2. Update of the California Net Load Curve with Historical Data for Years 2011–2016[1]

Traditional reliability measures do not comprehensively address these emerging issues. Evaluations of resource adequacy with probabilistic methods like loss-of-load probability traditionally focus on the ability of generation to meet demand while accounting for outages of generation or transmission. The traditional resource adequacy evaluations do not, however, account for unit commitment decisions under imperfect forecasts or the capability of generation to meet significant multi-hour ramps. In the past, a traditional loss-of-load probability analysis could be used to develop a simple metric, like a planning reserve margin, that would be sufficient to ensure reliability. That same planning reserve margin may not be enough to ensure adequate reliability in the face of increased variability and uncertainty that can impact loss-of-load probability. Given this limitation, there is growing recognition that traditional assessments of reliability need to be augmented with additional measures that adequately capture these issues related to flexibility. An initial effort to predict loss-of-load events that could be attributed to insufficient flexibility is described in a recent study funded by California utilities (Alvarez et al. 2017).

2.2 Analysis Approach

Our general approach is to compare the supply and demand for flexibility to see if they are in balance for a particular system in a particular state. The concept of "sufficient flexibility" requires a comparison of the need for the power system to be able to respond to variability and uncertainty (the flexibility demand) and the capability of the system to provide that response (the flexibility supply). It is not possible to determine if a system is sufficiently flexible by just measuring the demand for flexibility previously described. A complete assessment of flexibility requires examining the balance between flexibility demand and flexibility supply, as indicated on the left-hand side of Figure 2.3. An analogous example in reliability metrics is the planning reserve margin: this metric assesses the adequacy of the system by comparing the installed capacity (supply) to the peak load (demand), as indicated on the right-hand side of the figure.

[1] The CAISO forecasts have been updated with measured data by Scott Madden Management Consultants in their report *Revisiting the California Duck Curve: An Exploration of Its Existence, Impact, and Mitigation Potential* (October 2016).

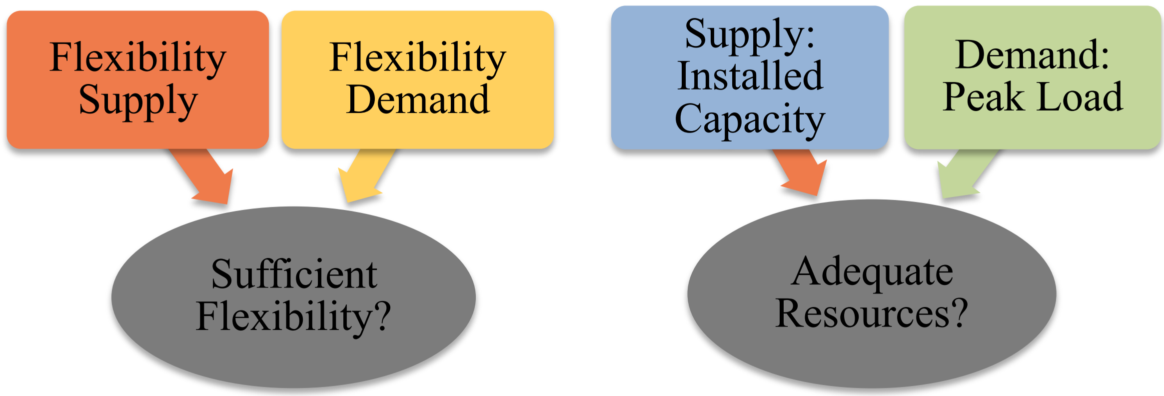

Figure 2.3. Flexibility and Capacity Demand and Supply

An alternative to directly measuring both flexibility supply and flexibility demand is to use indicators of *inflexibility*. One could identify metrics that indicate that flexibility supply is not always sufficient to meet flexibility demand, or that the challenge of meeting flexibility demand is getting harder. Analogs in reliability metrics are the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) metrics. Rather than directly comparing the demand and supply of electricity, these metrics instead assess reliability by measuring incidences of unreliability. In the remaining discussion of flexibility metrics, we will focus on these four categories of metrics: flexibility supply, flexibility demand, the balance between flexibility supply and demand, and measures of inflexibility.

A key challenge in reporting grid-related metrics is that DOE is neither responsible for providing primary supporting data, nor "owns" much of the data from which grid metrics are expected to be derived. An ideal outcome would be for the organizations that bear this responsibility to adopt metric methodologies developed, successfully tested, and accepted by a broad range of electric system stakeholders via GMLC1.1.

This project focuses on validating metric methodologies by applying them to real-world situations with electric sector partners and on establishing partnerships with key data providers, including federal agencies, state agencies, and regional entities that could potentially help institutionalize the final products and results of GMLC1.1.

3.0 Stakeholder and Metrics Users

A critical aspect of this project is to ensure that the metrics being developed directly benefit the electricity sector. Throughout the process of developing and testing the metrics from this project, input and feedback have been sought from stakeholders.

Key national organizations in the electricity industry were identified as Working Partners at the inception of the project and engaged to provide both strategic and technical input. Three types of organizations were also identified for each of the six individual metric areas: (1) primary metric users, (2) subject matter experts, and (3) data or survey organizations. These stakeholders were engaged at various stages of the project, especially at the beginning and scoping stages of the effort, as well as for more formal progress reviews.

Because independent system operators (ISOs) are charged with maintaining sufficient flexibility in the system to balance demand and supply at all times, they were viewed as key stakeholders to engage. ISOs that manage grids with large contributions from intermittent wind and solar generation face particularly acute flexibility challenges due to the variability and uncertainty associated with these resources. Accordingly, collaborations with the CAISO and the Electric Reliability Council of Texas, Inc. (ERCOT) were initiated. The CAISO currently has large contributions from a balanced portfolio of wind and solar generation, while the ERCOT system has a large wind component. Both ISOs provided years of historical data that were used to compute *lagging* flexibility metrics. Lawrence Livermore National Laboratory (LLNL) and the National Renewable Energy Laboratory (NREL) had previously conducted prospective studies for these ISOs using production cost models. Output from these production cost models is being used to compute *leading* flexibility metrics.

4.0 Outcome

4.1 Existing Metrics and Their Maturity

Due to the relationship between flexibility and system balancing, flexibility metrics are most usefully defined at the bulk power system level for balancing authorities or interconnections. Though industry recognizes the need for both additional flexibility and the need to measure system flexibility, flexibility only recently (less than a decade ago) emerged as an area of analysis. No standard metrics are in widespread use, but several industry actors are beginning to propose and use measures of flexibility, including stakeholders in Europe. Although some of these metrics have not been specifically designed to measure the flexibility of the system, they may be an appropriate surrogate. Existing metrics are categorized depending on whether the metric focuses on only flexibility demand (the amount of flexibility that is required), flexibility supply (the amount of flexibility that can be provided by dispatchable or controllable resources), the balance between flexibility supply and demand, or proxy measures that indicate insufficient flexibility. These metrics and examples of users are as follows:

- Metrics focusing on flexibility demand:
  - Variable energy resource penetration (Tennessee Valley Authority [TVA])
  - Flexibility turndown factor (TVA)
  - Net demand ramping variability (North American Electric Reliability Corporation [NERC] Essential Reliability Services Task Force [ERSTF])
  - Flexible capacity need (CAISO)
- Metrics focusing on flexibility supply:
  - System regulating capability (TVA)
  - Demand response (Federal Energy Regulatory Commission [FERC])
- Metrics focused on the balance between flexibility supply and flexibility demand:
  - Flexible resource indicator (Western Electricity Coordinating Council [WECC])
  - Periods of flexibility deficit (Electric Power Research Institute [EPRI])
  - Insufficient ramping resource expectation (EPRI/academic)
  - Flexibility metric (New England Independent System Operator [ISO-NE])
  - System flexibility (Puget Sound Energy)
  - Loss-of-load due to flexibility deficiency (Pacific Gas and Electric Company [PG&E], San Diego Gas & Electric Company [SDG&E])
  - Binding flexibility ratio (Lawrence Berkeley National Laboratory [LBNL])
- Metrics that use a proxy to indicate insufficient flexibility:
  - Renewable curtailment (Energy and Environmental Economics)
  - Percentage of unit-hours mitigated (FERC)
  - Control performance standards (NERC).

As with the other metrics, flexibility metrics can be separated into 1) lagging metrics that measure what has happened, and 2) leading metrics that can be used to support long-term planning, day-ahead market clearing, and real-time operational decisions about unit commitment or dispatch. Currently, there are no widely used and mature lagging metrics of flexibility that *directly* measure the flexibility of the power system. Instead, there are several indirect measures that may indicate when the power system was not sufficiently flexible. The indirect lagging metrics that show when the system had insufficient flexibility include unserved load, insufficient operating reserves, poor balancing control performance (e.g., low Control Performance Standard 1 [CPS1] scores), renewable curtailment, wholesale price volatility (including negative prices), or constrained ramp rates.

Balancing authorities, ISOs, and utilities already collect data for most of these indirect measures. Attributing outcomes to insufficient flexibility rather than inadequate capacity, however, will be challenging.

There are no standard leading flexibility metrics, but as indicated in the list above, there are growing numbers of examples from individual utilities and ISOs. The CAISO is developing a market product called the "flexible resource adequacy criteria-must offer obligation" (FRAC-MOO; CAISO 2014). Researchers at EPRI developed an IRRE metric and Periods of Flexibility Deficit to augment the traditional reliability metric of loss-of-load expectation. The Southwest Power Pool and ERCOT have been developing metrics to measure the flexibility value of transmission capacity and other grid properties. Examples of previous attempts to measure the flexibility of existing systems include comparison of generation types performed by the WECC, and a screening-level flexibility metric reported as part of a cross-country comparison in the International Energy Agency's (IEA's) Harnessing Variable Generation report (IEA 2011). Much of the information required to assess the flexibility of future portfolios can be obtained from standard production cost models that are regularly used in planning.

The existing metrics (listed below) used for other purposes are candidates for *leading* metrics describing *planning* flexibility. The exact relationships between these metrics and the amount of flexible generation or load needed for system planning purposes have not yet been developed. In general, these relationships would need to be developed using production cost and reliability models. In the second and third years of this project, we plan to work with ERCOT and CAISO stakeholders to quantify these relationships.

- Loss-of-load probability (LOLP) – This reliability metric is an output of grid reliability models that simulate generation and transmission outages. It is generally reported as an annual average at the utility or ISO scale. A value of one day in ten years is a reliability standard used by many grid planners. One possible direction for using LOLP as a flexibility metric is to first ensure that flexibility-related constraints or characteristics are represented in the models (e.g., ramp limits, unit commitment, forecast errors), then to separate loss-of-load events related to flexibility from loss-of-load events caused by traditional reliability issues (i.e., outages of conventional generators or transmission). The challenge to be addressed in using this approach is determining how to examine the details of each loss-of-load event realized in the simulation model so as to infer causality.
- Expected unserved energy (EUE) – The expected unserved energy (MW-hours) is another reliability metric that could be adapted to measure flexibility deficiencies, like the approach described above for LOLP. It is also usually reported as an annual average at the utility or ISO scale.
- Load forecast error – Errors in load and renewable forecasts with different time horizons provide one measure of the demand for flexibility at corresponding timescales.

Potentially useful *lagging* and *leading* metrics describing *operational* flexibility are listed below. The exact relationships between these metrics and operational flexibility have not yet been developed.

- Fraction of load under interruptible tariffs – Interruptible tariffs have been used for many years by load-serving entities across the country, generally for large industrial and commercial customers. At any point in time, the interruptible demand divided by total demand is one measure of flexibility in the system. Because large industrial and commercial loads under these tariffs typically have real-time metering, this metric could be computed in real time.

- Demand response – Similarly, demand response is a measure of flexibility in the grid. However, demand-response resources are also available from all customer classes at very disaggregated levels (e.g., individual air conditioners). This disaggregation makes it difficult to estimate how much flexibility is available at any given time because the loads are typically not metered in real time. In addition, availability varies with respect to advanced notice requirements for participating in day-ahead, hour-ahead, or real-time markets.
- Energy storage – Stored energy is a measure of the supply of flexibility at any point in time.
- Generator ramp rates – The aggregate ramping capability (MWs per minute) of the fleet of generators currently online is a measure of the supply of flexibility.
- Headroom – The difference between the maximum output of all dispatchable generators and the current load levels provides a measure indicating how long a given ramp rate can be sustained.
- Price volatility – Large changes in real-time prices may be indicative of insufficient flexibility in the system; in particular, negative prices are indicative of over-generation conditions that may be due to flexibility or transmission line outages.

As discussed in Section 4.2, metrics will be used individually and in combination to infer inadequate system flexibility.

4.2 Emerging and Future Metrics

Because of the importance of flexibility for integrating variable renewables, an inflexible system can lead to lower reliability, higher costs, and lower sustainability. Avoiding these consequences requires inclusion of flexibility assessments in both long-term planning and real-time operations to identify resource portfolios. Because no standard flexibility metrics exist, there is a need to establish core criteria for useful flexibility metrics (working with key users and stakeholders), identify flexibility metrics that can meet those criteria, and determine standard levels of flexibility that need to be met to pinpoint a system that is "sufficiently" flexible.

An accepted metric for a flexibility assessment can be used to demonstrate the feasibility of proposed future resource portfolios, to identify challenging operating conditions, to show the value of expanding the operating envelope of flexible technologies, and to determine a need for investment in more flexible technologies.

As indicated previously, multiple leading flexibility metrics have been proposed and are starting to be used in some settings, though a consistent definition is missing. Moving to a standard flexibility metric requires identification of core principles that can help evaluate the usefulness of these different proposed flexibility metrics and compare the different approaches. We have collected some examples of flexibility metrics and worked with some key stakeholders to identify core principles. In subsequent years of this project, we plan to evaluate different proposed flexibility metrics against these principles and to demonstrate application of flexibility metrics in particular locations.

Because the need for flexibility is likely to vary by region, season, and time of day, such flexibility standards must be dynamic in space and time. We will explore the development of metrics to estimate how much flexibility is needed and analyze metrics to describe how much flexibility is available. The goal will be to develop and assess clearly defined, measurable, and reportable metrics for flexibility that are analogous to standard metrics in production cost models for resource adequacy studies (such as a loss-of-load expectation [LOLE]) or area control error (such as Control Performance Standard 2 [CPS2] score). Application of these metrics to both operational analysis and capacity expansion will also be analyzed.

The team began by working in areas where flexibility is already of interest. We reached out to key stakeholders in California (investor-owned utilities, CAISO, California Public Utilities Commission [CPUC]) and Texas (ERCOT), and engaged with broader stakeholders who are interested in flexibility, including EPRI, NERC, and FERC.

Some of the indicators reflect inflexibility or reliability rather than a system's ability to adjust quickly to a new grid condition. A consistent definition of generation agility in ramping up or down and the ability of the transmission system to accommodate such ramps is missing. Recognizing the uncertainties in future build-out of the electric infrastructure, the grid must be able to adjust to new control paradigms, new market participants, and new technologies, preferably without the need for major long lead times and high cost reconfigurations. Metrics capturing these more strategic or planning-related flexibility capabilities will be of increasing value to future-proof the grid.

A robust approach to perform detailed system analysis that indirectly measures system flexibility using an established metric or new metrics is yet to be developed, though several promising approaches are emerging. As a paper from staff at the ISO-NE demonstrates (Zhao et al. 2016), system operators or planners could continuously run analyses with production cost, load flow, reliability, or other models that test the current capability of the system to respond to uncertainty. The ISO-NE staff proposes that the ratio of the capacity for uncertainty response to the expected range of uncertainty at any time could be a consistent measure system's flexibility at that time. Other proposed metrics for grid flexibility generally examine some probabilistic component of the need for system response to the variability and uncertainty of net load. A flexibility metric example is that of Lannoye et al. (2012, 2015), who introduced a probabilistic flexibility metric called the IRRE.

Metrics need to consider the need to evaluate both operational flexibility and incorporating flexibility in system planning. Most planning tools do not account for flexibility, and revisions to the common methods for least-cost capacity expansion have been proposed. Examples include those of Ma et al. (2013), who propose a new flexibility metric and a capacity-expansion model that accounts for flexibility needs and builds units to meet them. The metric is a normalized average of the ramp range and hourly ramp rate for all the generators in the system.

4.2.1 Potential New Flexibility Metrics

Potential new flexibility metrics for representation of operations in a planning model and for use directly in operations are listed below. They are still in the experimental stage.

1. LOLE_flex – The LOLE due to a deficiency in ramping capability over some short time period (<1 hour) as opposed to insufficient capacity on line. A multi-hour metric, LOLE_multihour has been developed in a recent study funded by California utilities (Alvarez et al. 2017). This leading metric would be an output of production planning models. It has not been considered for use outside of California, so collecting data from other areas would require modification of their respective production cost models.
2. IRRE – The IRRE leading metric has been proposed by EPRI. It is similar to LOLE_flex. As mentioned earlier, EPRI is also using the Periods of Flexibility Deficit metric.
3. Flexibility ratio – This is the ratio of flexibility supply to flexibility demand. It has been used in several Integrated Resource Plans in California.

4. Wind generation fraction – Leading metrics using weather and production cost models could be used to characterize demand for flexibility. Lagging metrics could be used to identify trends and correlations (e.g., high wind generation and load shedding may indicate insufficient intra-hour ramping capability was available at that time). Large fractions of generation coming from wind can lead to a range of challenges.
5. Solar generation fraction – Leading metrics using weather and production cost models could be used to characterize demand for flexibility. Lagging metrics could be used to identify trends and correlations (e.g., high solar generation and load shedding may indicate insufficient multi-hour ramping capability).
6. Wind generation volatility – Standard deviation, autocorrelation, or other statistical measures may provide a valuable metric for estimating the demand for flexibility.
7. Solar generation volatility – Standard deviation, autocorrelation, or other statistical measures may provide a valuable metric for estimating the demand for flexibility.
8. Net load forecast error – Historical net load forecast errors can be characterized and used to estimate the demand for flexibility. Forecast errors should be examined for multiple timescales, including 5-minute, 1-hour, and 4-hour time periods. This metric could be used to characterize demand for flexibility.
9. Net load factor – Mean divided by peak load net of renewable generation by time of day, season, and weekday/weekend. This metric could be used to characterize demand for flexibility.
10. Maximum ramp rate in net load – Ramp rate (MWs per minute) over various timescales, including 5-minute, 1-hour, and 4-hour time periods. This metric should be computed for different times of day, season, and weekday/weekend. It could be used to characterize demand for flexibility.
11. Maximum ramp capability – Ramp capability of dispatchable fleet (MWs per minute or percent of total generation) over 5-minute, 1-hour, and 4-hour durations.
12. Energy storage – Total energy storage in MW and MW-hours. This will depend upon season for hydroelectric resources.
13. Demand response – Expand on the FERC metric to include the dependence of demand response upon season, time of day, advance notification lead time, duration, rebound ratio, and other factors. Include MW and MW-hour metrics.
14. Inter-regional transmission capacity – Transmission capacity in and out of the balancing area. Capacity should be specified by season, time of day, and advance notification requirements. Transmission capacity utilization is a related metric that could be used.
15. Intra-regional transmission capacity – Transmission capacity within the balancing area. Capacity should be specified by season, time of day, and advance notification requirements. Components of this metric could include the fraction of the time at least one transmission line is at capacity, system average transmission line utilization, energy not transferred due to congestion, and congestion charges as a fraction of total energy costs. Metrics previously developed by FERC in this area will be used where deemed appropriate by stakeholders.
16. Interruptible tariffs – The fraction of energy consumption that is under interruptible tariffs with various constraints on advance notice (e.g., day-ahead, hour-ahead, or no notification required).
17. Renewable wind curtailment – Wind curtailments imposed during operations are an indication that the system design or operating policies do not provide sufficient flexibility. They should be normalized to the total system load, renewable nameplate capacity, or some other system metric. Estimating the total quantity of MW-hours curtailed will likely require weather data or modeling to estimate what the output could have been during curtailed hours.

18. Solar curtailment – Solar curtailments imposed during operations are an indication that the system design or operating policies do not provide sufficient flexibility. Solar curtailments should be normalized to the total system load, renewable nameplate capacity, or some other system metric. Estimating the total quantity of MW-hours curtailed will likely require weather data or modeling to estimate what the output could have been during curtailed hours.
19. Negative prices – Negative prices during periods of over-generation could be measured as a fraction of the hours in the year prices are negative, or as the product of negative prices and MW-hours delivered at that price.
20. Positive price spikes – Short-term positive price spikes during periods of under-generation could be measured as a fraction of the hours in the year prices exceed a given threshold, or as the product of excessive positive prices and MW-hours delivered at that price.
21. Load shedding – Historical data to be used as a lagging metric are readily available, but it would be difficult to determine whether load shedding was due to lack of flexibility or other causes. Leading metrics would be based upon production cost and reliability modeling to estimate LOLE due to flexibility limitations. It is useful to partition this metric into intra-hour and multi-hour events. A study sponsored by PG&E and SDG&E currently under way takes this approach (CPUC—Flexibility Metrics and Standards 2016)
22. Operating reserve shortage – Historical data documenting periods when operating reserves are below minimum requirements are readily available, but it may be difficult to attribute these events to lack of flexibility. For leading metrics, production cost and reliability models could be used. Historical prices for flexible ramping reserves can also be used.
23. Control performance (e.g., CPS1, CPS2, Balancing Authority Area Control [ACE] Limit [BAAL], etc.) – Historical data are readily available. Violations may be due to lack of flexibility, but it will be difficult to infer causality. For leading metrics, production cost and reliability models could be used.

We worked with stakeholders to screen this long list of potential metrics to identify ones that are most useful and reliable. Some driving factors for assessment are the metrics' ability to inform decisions that lead to capital cost savings, operating cost savings, greenhouse gas reductions, and convenience/inconvenience of the grid services user.

The metrics can be used individually and in combination to infer causality and to inform system planning decisions and operating policies. For example, if a wind curtailment occurs coincident with a large net load forecast error, the lack of flexibility could be attributed to forecast accuracy rather than insufficient ramping capability in the system. Ramping capability may have been present, but generators may not have been dispatched to the right point to accommodate the rapid increase in net load. Similarly, a load-shedding event coincident with high inter-regional transmission line loading indicates that transmission capacity may be the cause of insufficient flexibility.

4.3 Statistical Analysis with Lagging Metrics

Historical data from CAISO and ERCOT archives were used to compute flexibility metrics. Results were briefed to DOE and external reviewers on April 5, 2018, and a manuscript for submission to a journal is currently being prepared. Some key results are provided here.

Lagging metrics characterizing flexibility demand and indicators of inflexibility were computed using historical data provided by CAISO and ERCOT. As indicated in Table 4.1, these metrics address three flexibility challenges: 1) avoiding over-generation during times of peak solar or wind output, 2) meeting high net load ramps in the afternoon as solar generation falls and gross load rises, and 3) accommodating the uncertainty in renewable generation.

Table 4.1. Taxonomy of Flexibility Metrics

Dimension of Flexibility	Flexibility Demand	Indicator of Inflexibility
Over-generation (belly of the duck)	Ratio of peak to minimum	Renewable curtailment, negative prices
Ramping (neck of the duck)	Ramp rates of net demand	Price spikes, out-of-market actions
Uncertainty (waddle of the duck)	Net demand forecast errors	Real-time price premium, cost of forecast errors

In the following subsections, we display historical patterns of these indicators of inflexibility for the CAISO and ERCOT systems.

4.3.1 Over-Generation

Historical data from January 2013 through December 2017 were downloaded from the CAISO archives. The minimum net demand for each hour of this 5-year period is displayed in Figure 4.1. In preceding decades, minimum net demand in California was experienced between midnight and 4:00 am. The data in the figure show that now minimum net demand occurs around noon each day, and the trend is getting more pronounced (deeper purple shades). This is due to high levels of solar photovoltaic (PV) generation during these hours, which is subtracted from gross demand to calculate net demand.

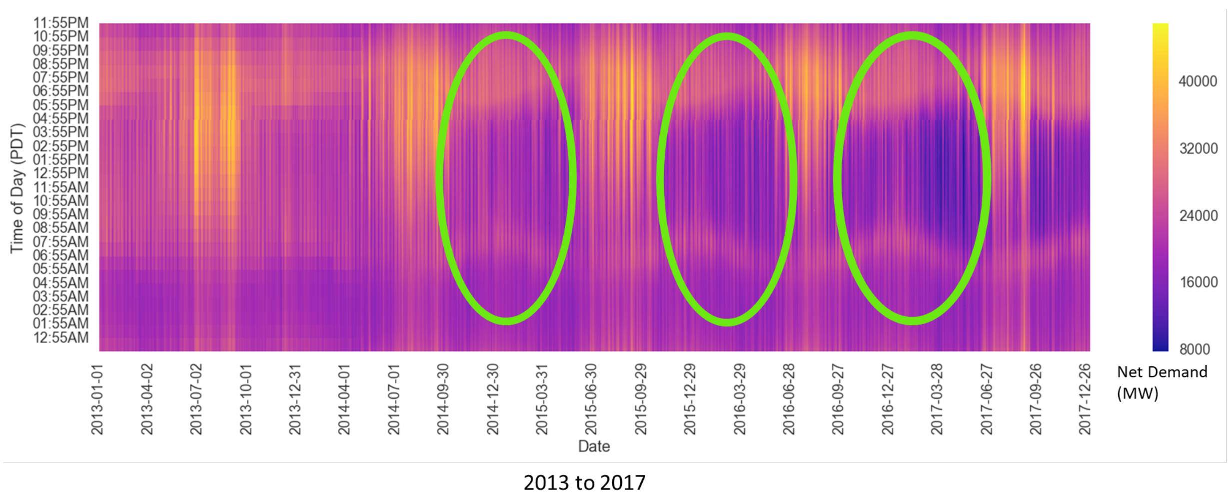

Figure 4.1. CAISO Minimum Net Demand (MW)

Another potential indicator of insufficient flexibility is the presence of negative prices. Figure 4.2 shows that negative prices are often experienced during hours of maximum solar PV generation. As indicated in the figure, these over-generation conditions tend to occur in the spring.

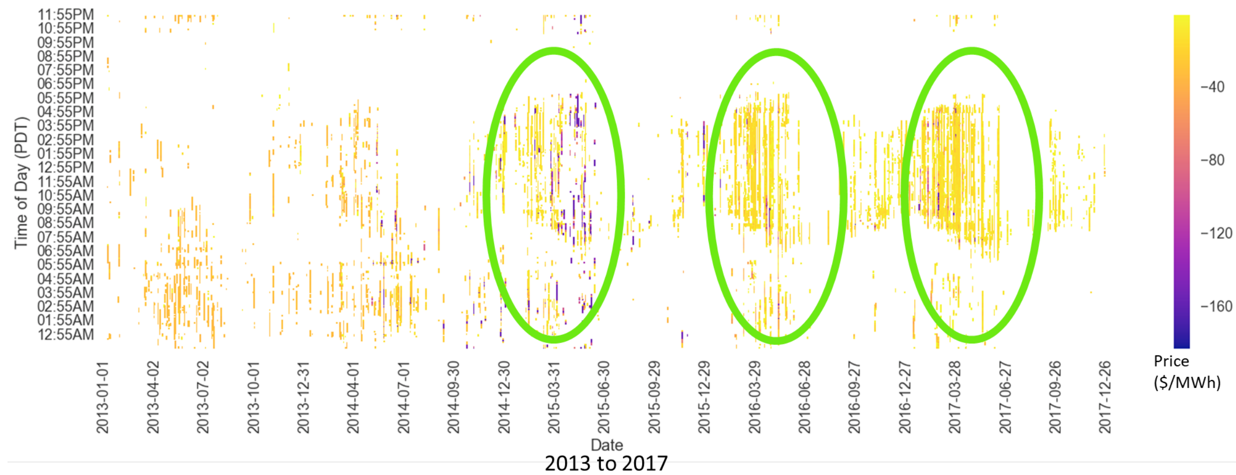

Figure 4.2. CAISO Negative Prices ($/MWh)

To address the over-generation conditions, CAISO sometimes resorts to curtailment of renewables. Renewable curtailment during this 5-year period is shown in Figure 4.3. The amount of curtailed energy is increasing over time.

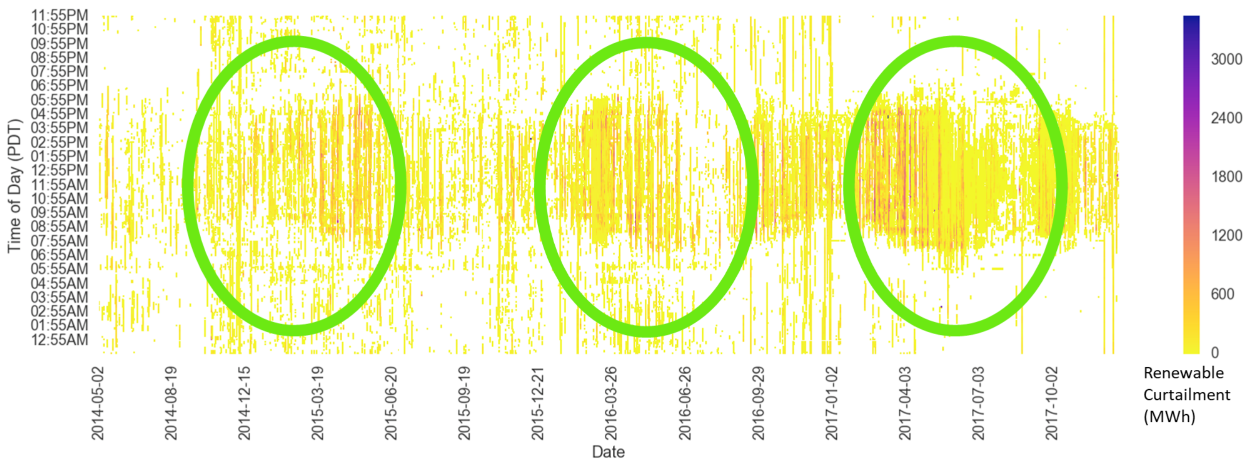

Figure 4.3. CAISO Renewable Curtailment (MWh)

Historical data from January 2011 through December 2016 were also downloaded from the ERCOT archives. While renewable generation in the CAISO system is provided by a mix of wind and solar generators, wind generation is the only significant renewable contribution in the ERCOT system. The minimum net demand for each hour of this 6-year period is displayed in Figure 4.4. The data in the figure show that minimum net demand occurs in the afternoon during the summer. As indicted by the red circles in the figure, multi-day wind events occur during the winter.

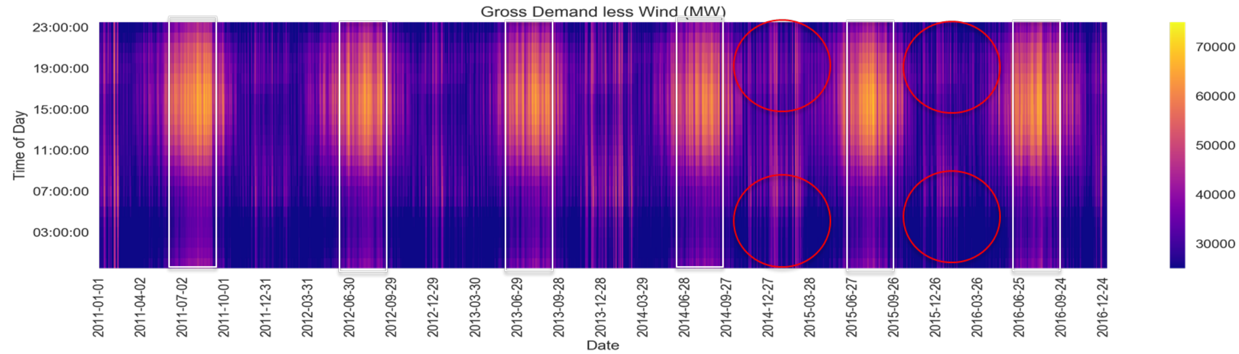

Figure 4.4. ERCOT Minimum Net Demand (MW)

Figure 4.5 shows that ERCOT experiences occasional negative prices in the early morning hours of the winter months.

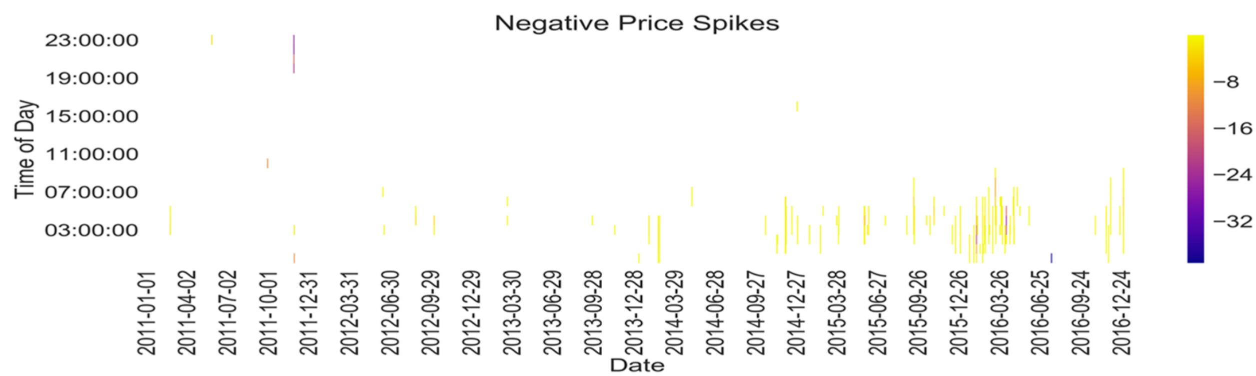

Figure 4.5. ERCOT Negative Prices ($/MWh)

Renewable curtailments are shown in Figure 4.6. The data show substantial curtailments during 2011 and early 2012. Transmission system upgrades in ERCOT significantly reduced curtailments after that period. However, curtailments increased in the spring and winter of 2016.

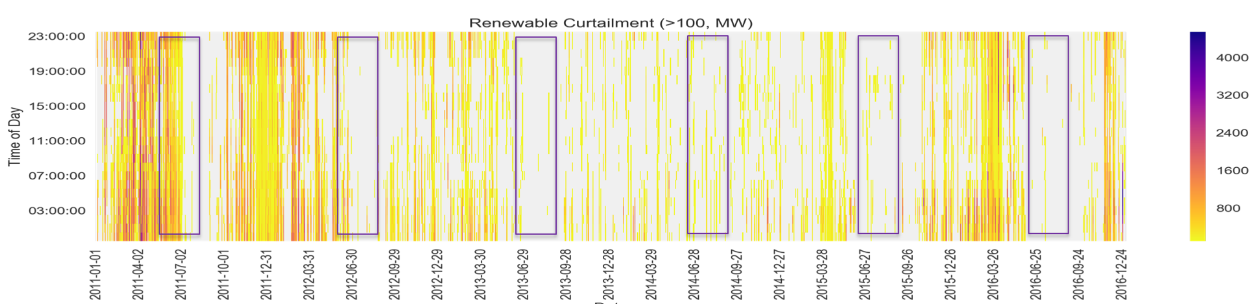

Figure 4.6. ERCOT Curtailment (MWh)

4.3.2 Ramping

Variable generation from renewable resources can increase the need to ramp dispatchable units in the system. Net ramp rates for the CAISO system are shown in Figure 4.7. The data show high rates of net ramp up during the early evening and early morning, with the exact timing varying by season (yellow sinusoidal regions at the top and bottom of the figure). Ramp rates reached +/-4000 MW/hr for a system with a total load of 30,000–50,000 GW.

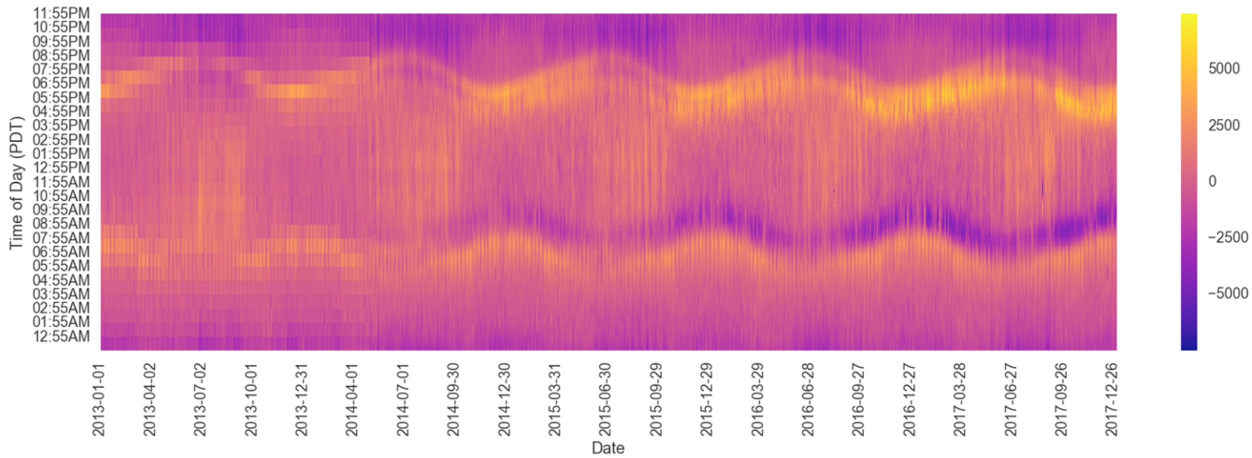

Figure 4.7. CAISO Net Ramping (MW/h)

Figure 4.8 shows how ramp rates have increased over time. The solid bars show the 95th percentile for each year and the dashed lines show the corresponding 5th percentiles. During the years 2013 to 2017, the afternoon ramp rate grew from 3000 MW/hr to 4500 MW/hr. Moreover, this high ramp rate persisted for several hours per day(?) in 2017.

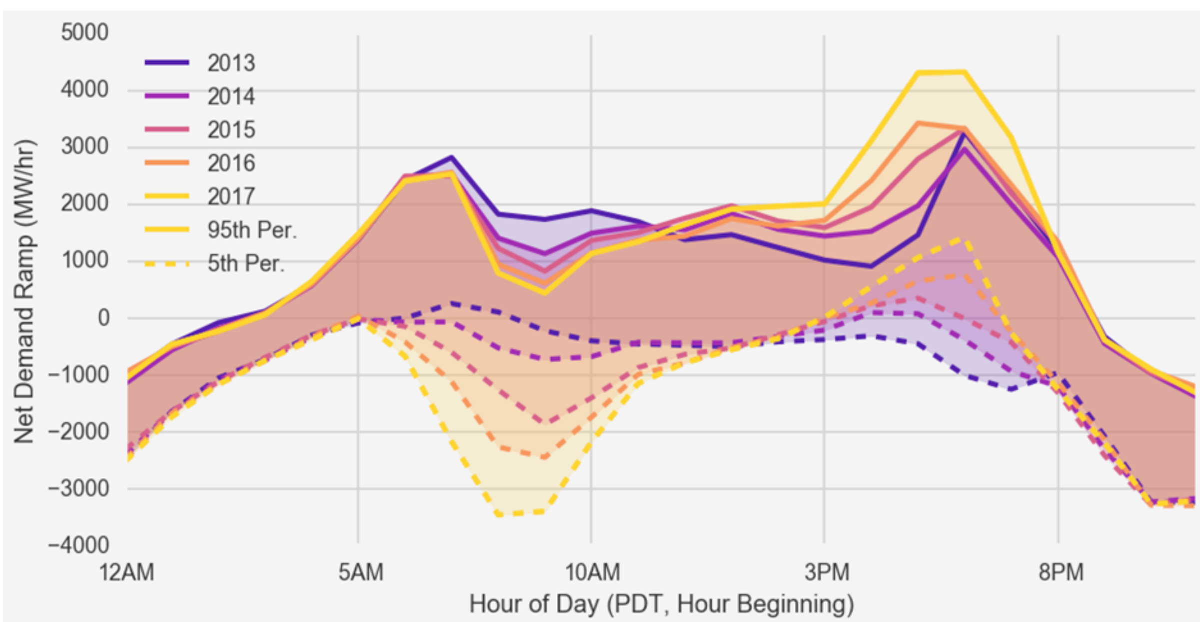

Figure 4.8. CAISO Net Ramping Growth (MW/h)

Ramp rates for ERCOT are shown in Figure 4.9. In this wind-dominated renewable system, the highest positive ramp rates are experienced in the summer mornings and the highest negative ramp rates occur after 19:00 hours. The data in Figure 4.10 indicate that ramp rates have not changed significantly during the period 2011 through 2016.

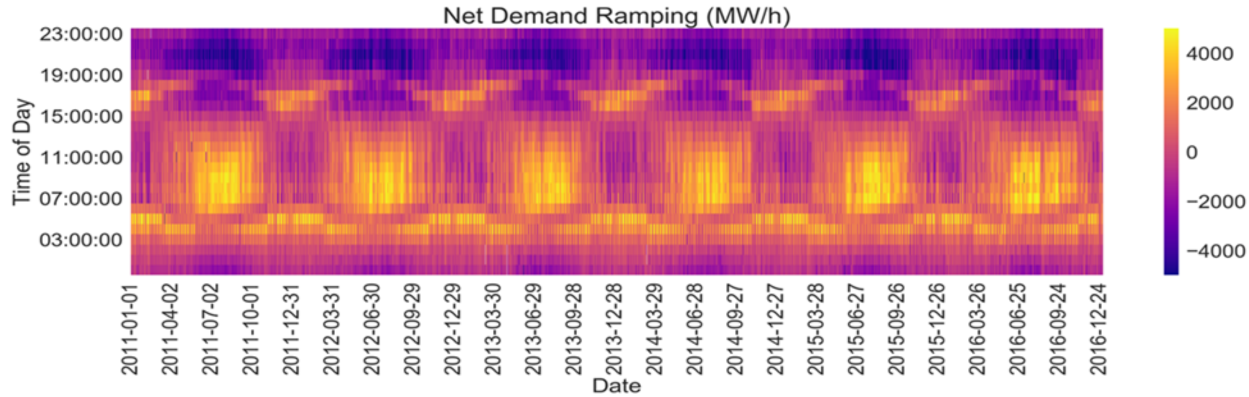

Figure 4.9. ERCOT Net Ramping (MW/h)

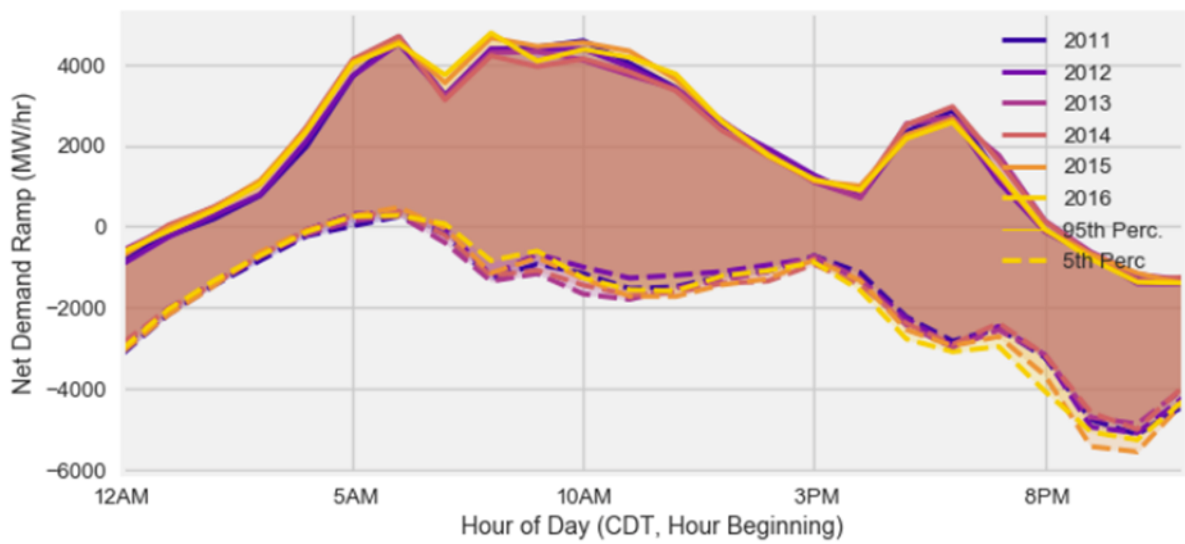

Figure 4.10. ERCOT Net Ramping Growth (MW/h)

4.3.3 Uncertainty

CAISO and ERCOT conduct day-ahead auctions to match buyers and sellers of electricity. On the next day, price adjustments are made to match demand and supply in real time. With perfect forecasting, the day-ahead and real-time prices would be identical. However, uncertainty in demand, renewable generation, and grid component operating status can cause them to differ. For example, if net demand is underestimated in the day-ahead market, prices in the real-time market would tend to be higher as the ISO procures resources at higher prices in real time. The spread between the day-ahead and real-time prices is referred to as the real-time price premium.

CAISO real-time price premia for the study years 2013–2017 are shown in Figure 4.11. As indicated in the figure, the 95th percentile of the premium in the afternoon has increased steadily during the study period from \$50/MWh to almost \$200/MWh. The price premium can also be negative during this period, reflecting unanticipated over-generation conditions.

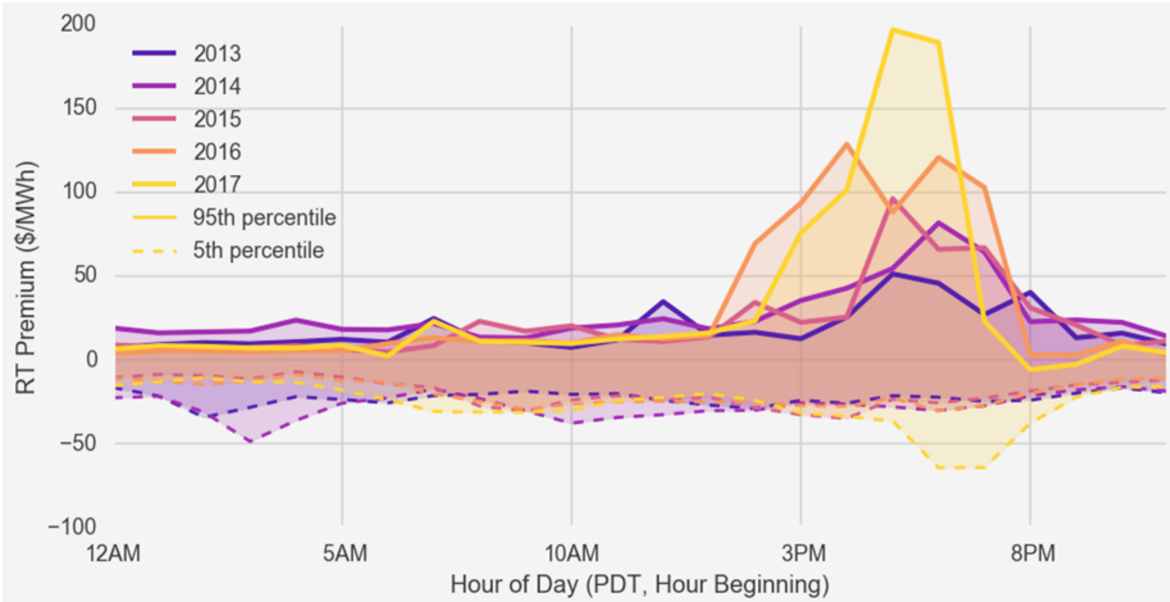

Figure 4.11. CAISO Real-Time Market Premium ($/MWh)

ERCOT real-time price premia for the study years 2011–2016 are shown in Figure 4.12. There is a negative bias in the price premium distribution in the afternoon hours.

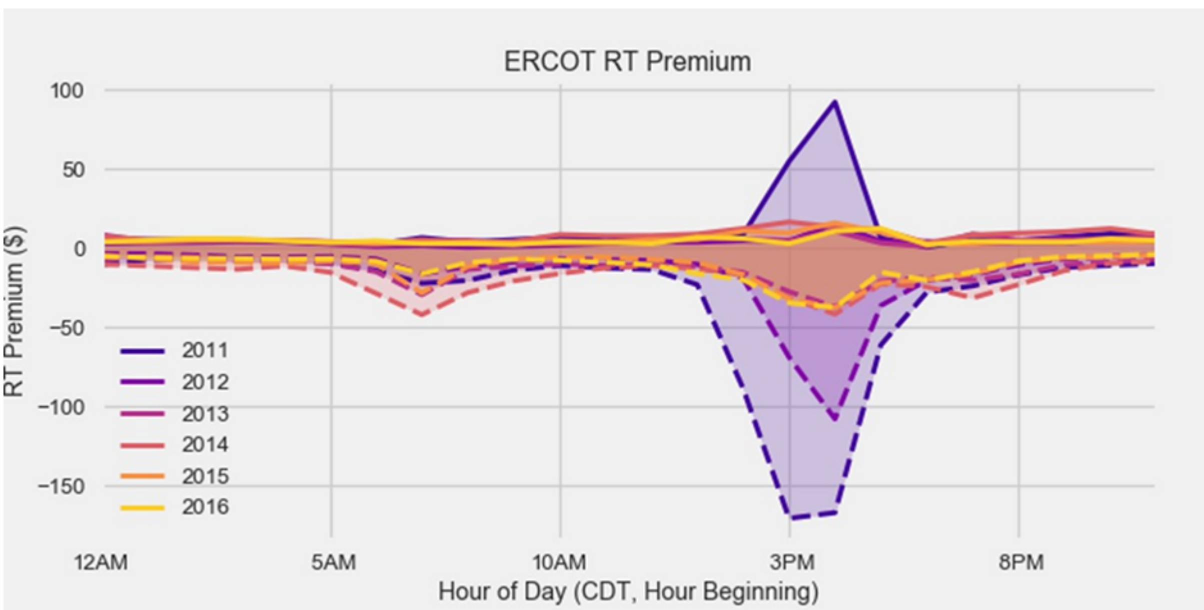

Figure 4.12. ERCOT Real-Time Market Premium ($/MWh)

4.3.3.1 Conclusions for Historical Metrics

The figures above(?) show the timing and magnitude of each of the three things that indicate the need for flexibility: over-generation, ramping, and uncertainty. Summary metrics can be computed from the raw data that would inform policy decisions. For example, sums of negative prices and curtailments in the summer months between 9:00 a.m. and 5:00 p.m. would provide rough indicators of needed electric vehicle charging capacity during work hours. This would inform programs that subsidize installation of electric vehicle chargers in office building garages. Also, the reduction in the ERCOT RT risk premium during the 2011 to 2016 period indicate that the transmission infrastructure implemented, and other changes to, the system in Texas during this time period have dramatically reduced uncertainty. No other infrastructure or market modifications are needed to address this dimension of flexibility. Additional metrics that may indicate an imbalance between flexibility supply and demand, such as out of merit order dispatch and high price spikes, could be computed.

4.3.4 Use of Production Cost Models to Assess Flexibility

Results from previous runs of production cost models are being used to generate leading metrics associated with flexibility. A production cost model simulates a least-cost unit commitment and dispatch over a period of time to establish which resources—generators, storage, or demand response—must be online to meet the electricity demand and supply reserves for operational reliability, and to satisfy other system constraints. The models calculate the total operational cost of system operation and include measures of system reliability, such as unserved load and reserve violations.

The models can estimate multiple impacts of increased flexibility. In the most extreme case, they can measure unserved energy resulting from the inability to meet ramp rate requirements. The more likely impact of insufficient flexibility is typically due to increased costs, including inefficient dispatch and curtailment. The increase or decrease in system costs that results from changes in flexibility can be measured from runs that simulate the system before and after any flexibility measure is introduced.

4.3.4.1 Solar PV Penetration Impacts

An example of the application of a production cost model to evaluate system flexibility is shown in Figure 4.13 and Figure 4.14 using <u>three</u> different flexibility metrics: (1) renewable curtailment, (2) operational savings, and (3) renewable economic carrying capacity. The example studies the California grid under increased penetration of solar PV (Denholm et al. 2016). Four flexibility measures were introduced relative to the base case: 1) added 1,290 MW of new storage, roughly following the California storage mandate; 2) changed the instantaneous variable generation (VG) penetration limit from 60% to 80%; 3) removed a 25% local-generation requirement; and 4) allowed curtailed VG to provide upward regulation, contingency, and flexibility reserves.

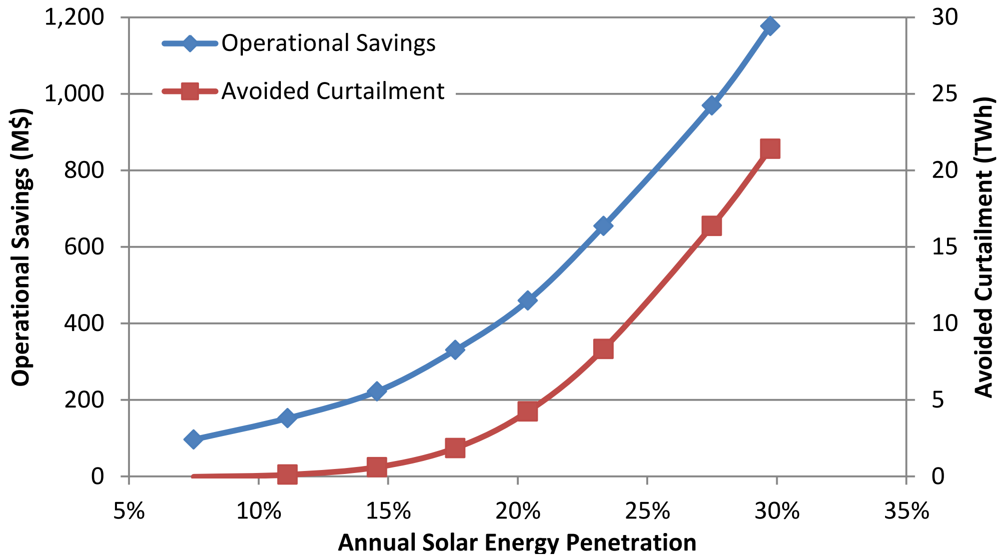

Figure 4.13. Operational Savings and Curtailment Reduction Associated with Added Flexibility

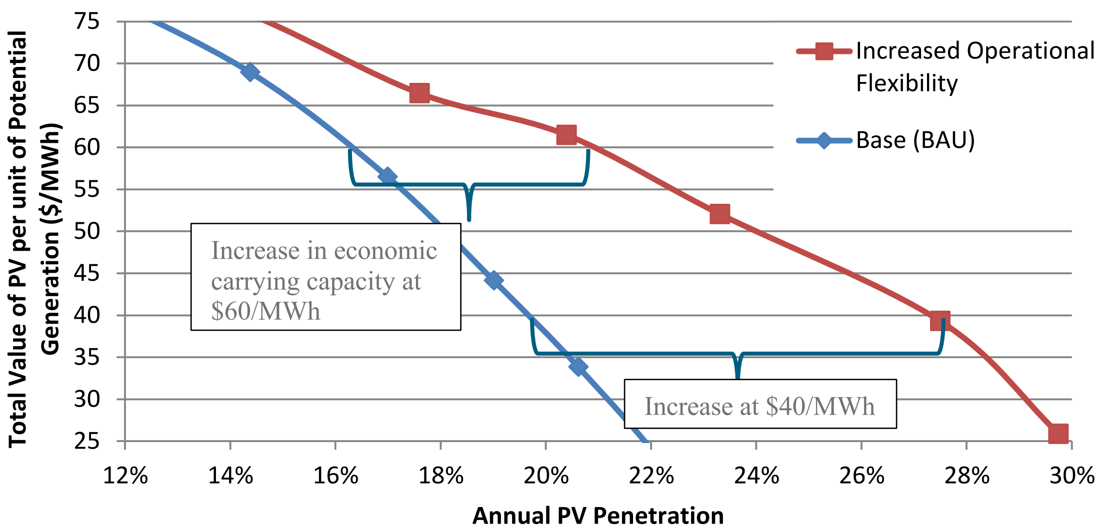

Figure 4.14. Increase in Economic Carrying Capactiy Resulting from Increased Operation Flexibility

Figure 4.13 shows the operational savings as a function of PV penetration for the increased operational flexibility case, as well as avoided PV generation curtailment. The base case represents a "business-as-usual" scenario, representing traditional operating practices prior to 2016, including multiple restrictions on the flexibility of thermal power plants, interaction with neighboring regions, and provision of reserve services from VG. The increased operational flexibility case represents changes that are under way and will likely be implemented by 2020 (CPUC 2015). These changes include allowing greater use of VG for provision of reserves and reliability services, as well as the addition of over 1,000 MW of new storage in response to the California storage mandate (Eichman et al. 2015). Note that for this study, several different flexibility metrics are changed at the same time. Production cost models could also be configured to investigate the impact of making each of the changes in isolation.

The gain in flexibility also reflects the increased ability of the system to accommodate VG. One approach to estimating the limits to VG deployment is to determine the penetration of VG (i.e., the fraction of a system's energy met by VG) at which the costs outweigh the benefits and where additional VG is no longer economically desirable. This can be measured as *economic carrying capacity* (ECC) (Cochran et al. 2014). Fundamentally, an ECC results from the decline in the value of renewables as they are added to the grid (Mills and Wiser 2012). Figure 4.14 shows the value decline of PV in California for two flexibility cases. The figure shows the increase in ECC from about 16% of annual load to about 21% of annual load derived from PV (a spread of about five percentage points), assuming a $60/MWh Levelized Cost of Electricity (LCOE). As PV prices decrease (shown in the lower-cost PV line at $40/MWh), the increase in ECC is greater, or about eight percentage points from about 20% to about 28%.

Hence, this section shows how a variety of flexibility measures can aid in integrating PV and lower system costs. The following sections do deep-dives on specifics and show how individual technologies respond to provide flexibility "services."

4.3.4.2 Demand Response for Load Following

Demand response provides another source of flexibility. Output from production simulation runs conducted for a previous study were used to characterize the ability of demand response as a source of flexibility supply (Edmunds et al. 2017a). This study simulated operation of the WECC with 33% renewable generation in California. Load following demand response dispatched in the PG&E San Francisco Bay area is shown in Figure 4.15. As indicated in the figure, 100–200 MW of demand response is exercised to meet evening peak demand at around 18:00 hours. There is some seasonal variation in usage, with demand response being exercised later during the summer months.

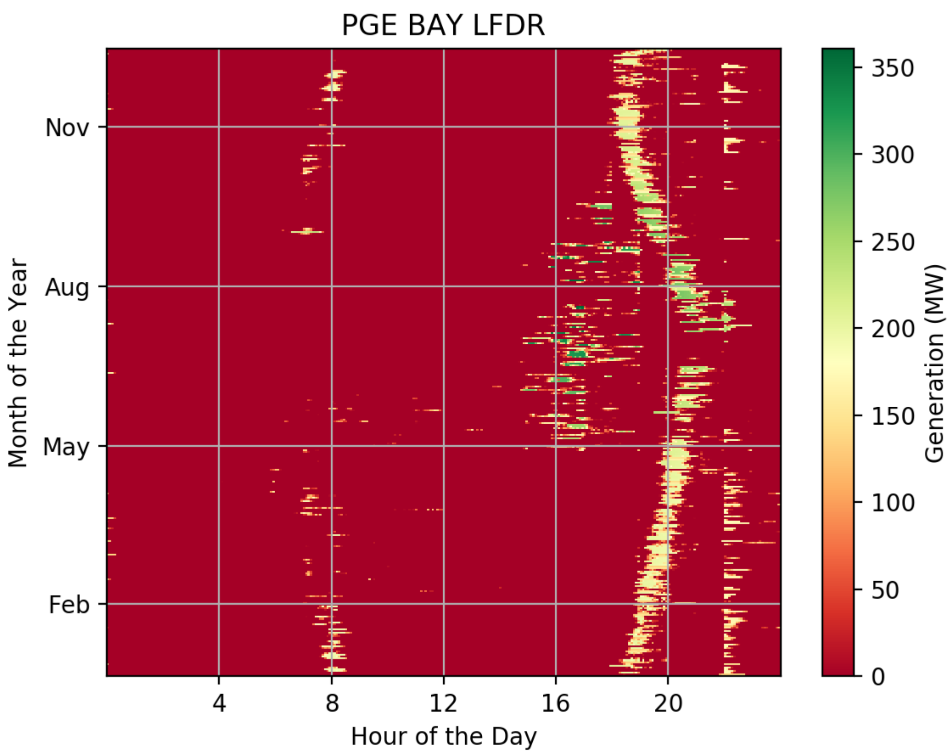

Figure 4.15. Load Following Demand Response Dispatched in San Francisco Bay Area

Figure 4.16 and Figure 4.17 show that similar patterns of demand response usage are present in the Los Angeles and San Diego areas, respectively.

These production cost runs provide a metric measuring how much flexibility a given capacity of demand response at a specified dispatch price can provide. The model can be run with a range of dispatch prices to generate a supply curve for demand response. Policymakers can use this supply curve to inform decisions regarding programs that encourage deployment of demand-response technologies. As indicated by the usage patterns in the figures, demand-response resources that would be available during the peak usage hours shown would be most valuable. Demand-response resources with operating constraints that would preclude them from being dispatched during these hours could also be modeled. The relative value of different demand-response technologies can be characterized, and incentive programs implemented, accordingly.

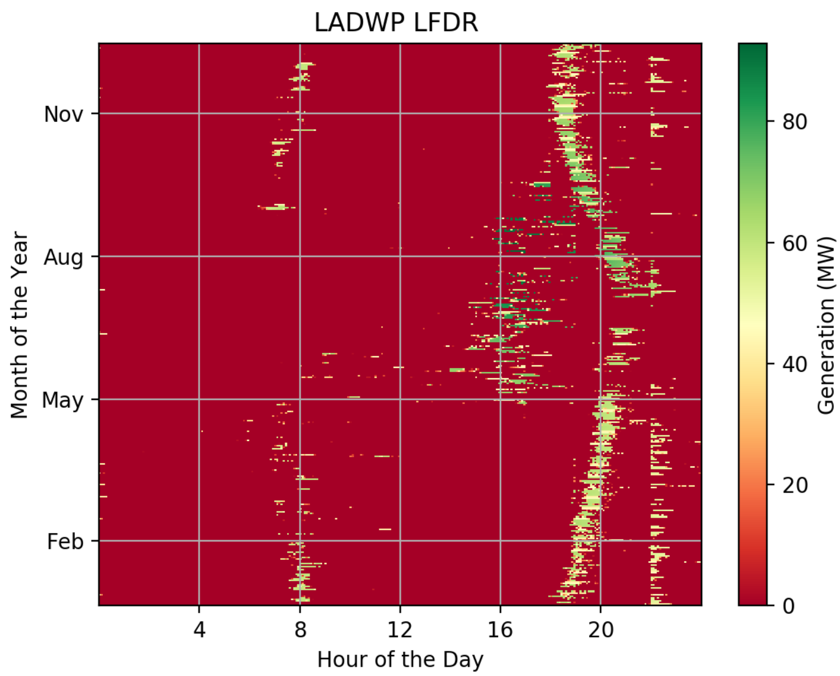

Figure 4.16. Load Following Demand Response Dispatched in Los Angeles Area

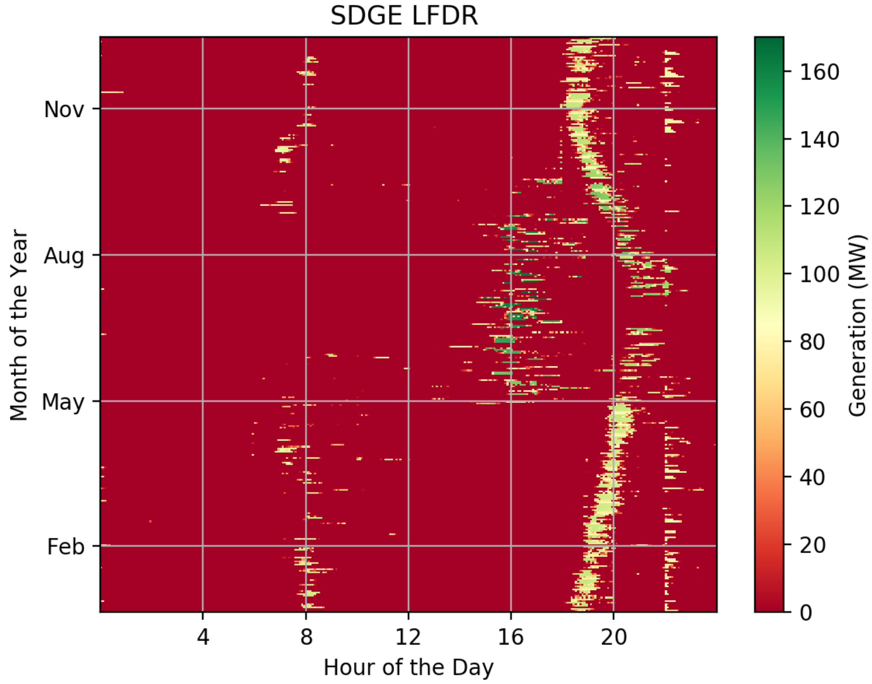

Figure 4.17. Load Following Demand Response Dispatched in San Diego Area

4.3.4.3 Flexibility via Power Flow Between Neighboring Balancing Authorities

Flexibility for an area can also be provided by power flow between neighboring states. Model results show power flows between California and neighboring states in the Southwest and Northwest US that levelized load throughout the region. Power flows between Canada and the northernmost US states are also shown.

Figure 4.18 shows the power flow from Arizona to California. Power flow is positive (from Arizona to California) except during winter months in the middle of the day when loads are low in California, but renewable generation is high. As the chart title indicates, power flow is aggregated over all transmission lines between California and Arizona.

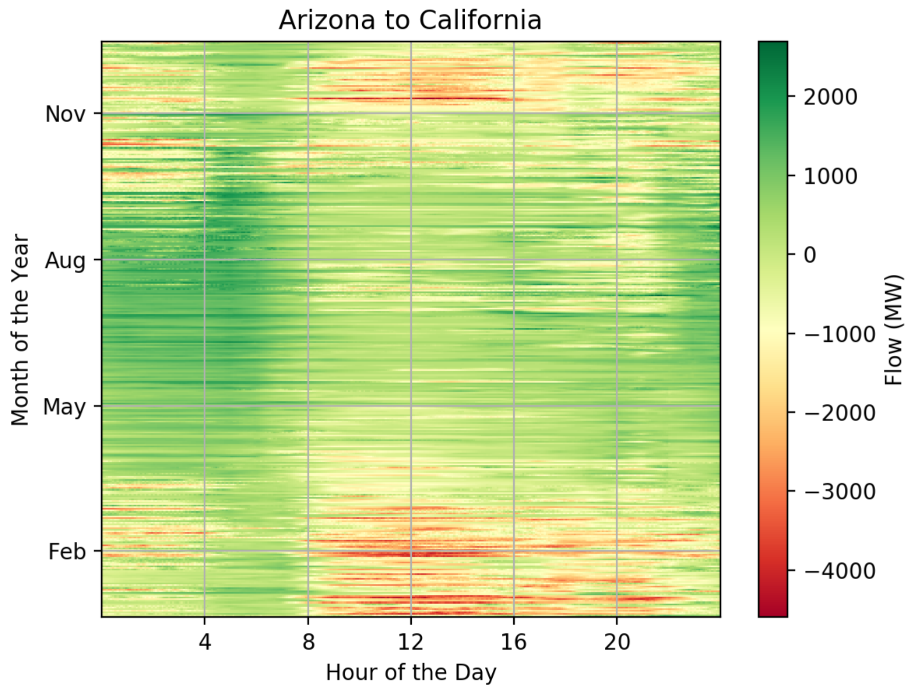

Figure 4.18. Arizona to California Aggregated Power Flow

As shown in Figure 4.19, power flow from New Mexico to California is positive throughout the year. Power flow is lower during the summer months due to the high solar penetration in California and large air conditioning loads in Arizona and New Mexico. The pattern of flow from New Mexico to California is consistent with that observed from Arizona to California.

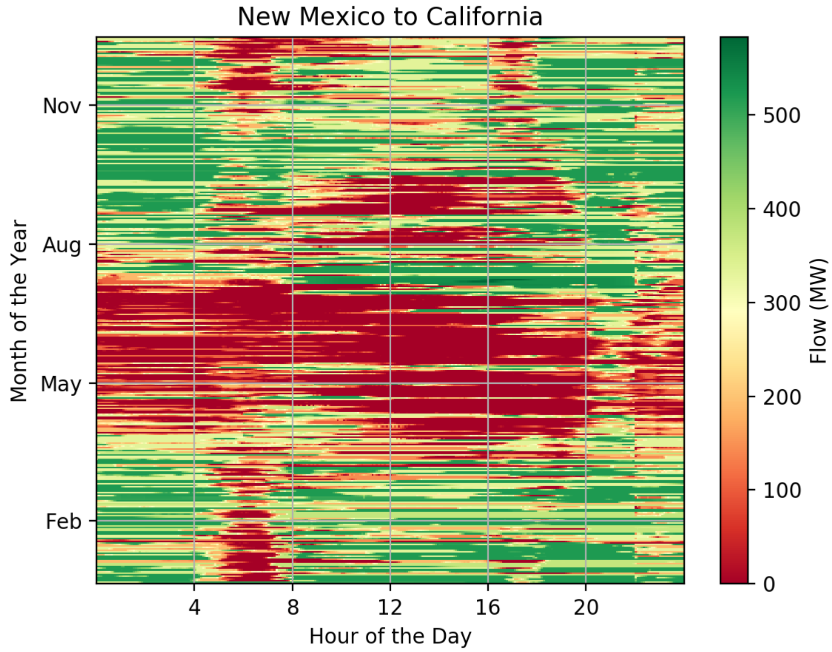

Figure 4.19.. New Mexico to California Aggregated Power Flow

Figure 4.20 shows the power flow from Nevada to California. For most of the year California receives power from Nevada, with the Hoover Dam being one of the main contributors to this power exchange. The red horizontal bands in the graph indicate that small amounts of power are shipped from California to Nevada for several weeks at a time at various times of the year.

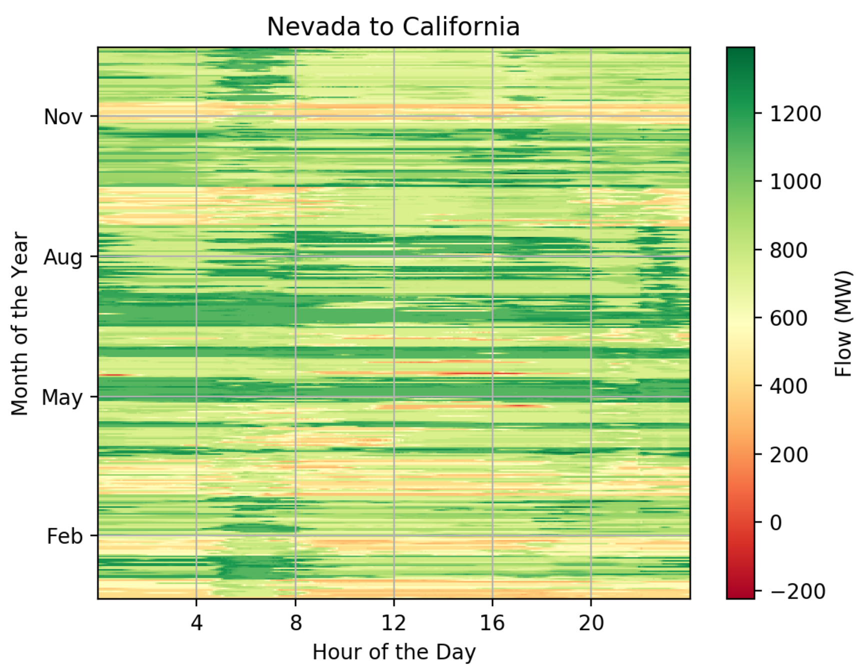

Figure 4.20. Nevada to California Aggregated Power Flow

Figure 4.21 shows the power flow from the Pacific Northwest region to California. There is a clear pattern throughout the entire year: California sends power to the Northwest during high solar generation hours, while the Northwest sends power to California early in the morning and late at night when California's solar generation is low or zero and wind/hydro generation is high in the Northwest.

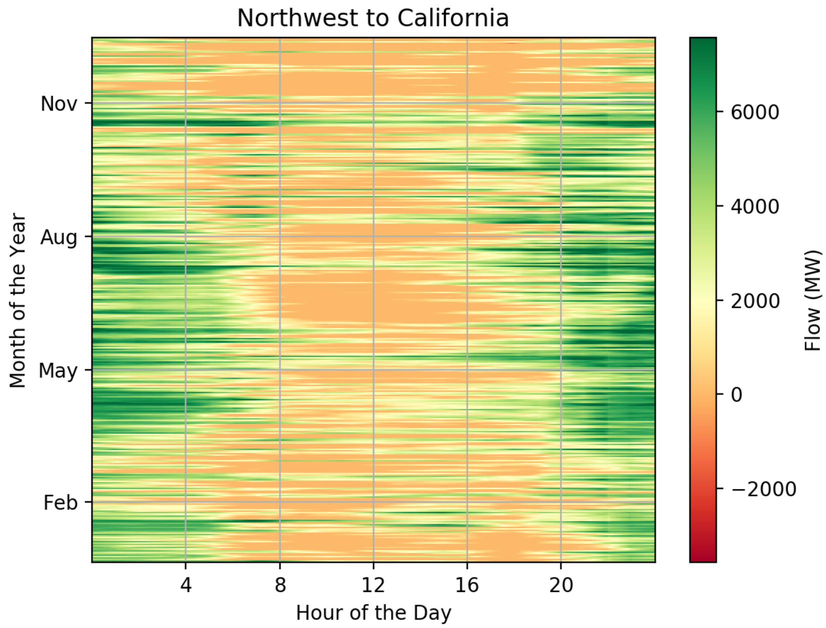

Figure 4.21. Pacific Northwest to California Aggregated Power Flow

Figure 4.22 shows the power flow from Utah to California. During the midday hours there is almost no power exchange, but California starts exporting power to Utah during the early evening hours. California's early evenings tend to feature increasing winds just as load is dropping after the evening peak.

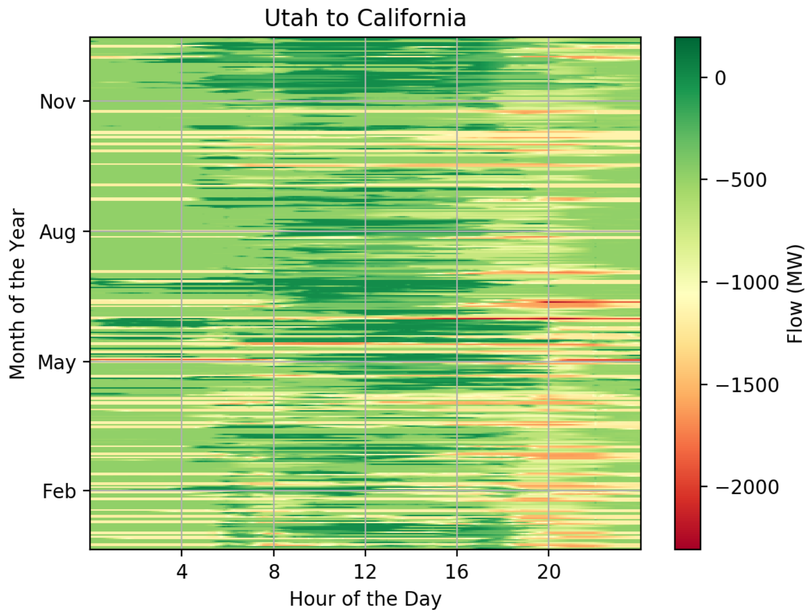

Figure 4.22. Utah to California Aggregated Power Flow

Figure 4.23 shows the power flow from Mexico to California. For the entire year power flows from Mexico to California, though transfer is lower during midday due to significant numbers of solar installations in California.

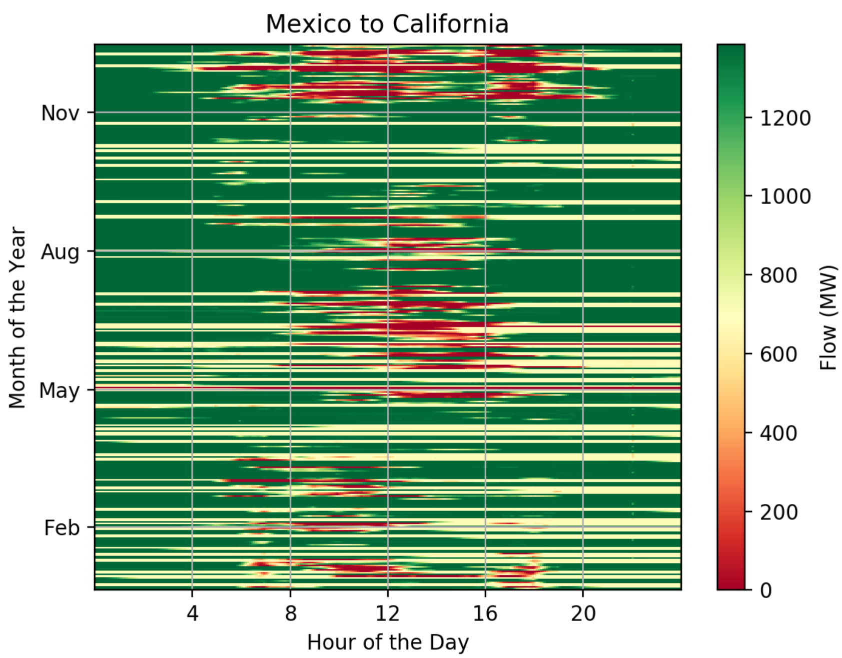

Figure 4.23. Mexico to California Power Flow

Figure 4.24 shows the power flow from Alberta, Canada (AESO) to Northwest Montana (NWMT). For most of the year Montana sends power to Alberta. However, AESO helps NWMT cover a resource deficiency in July during peak load periods.

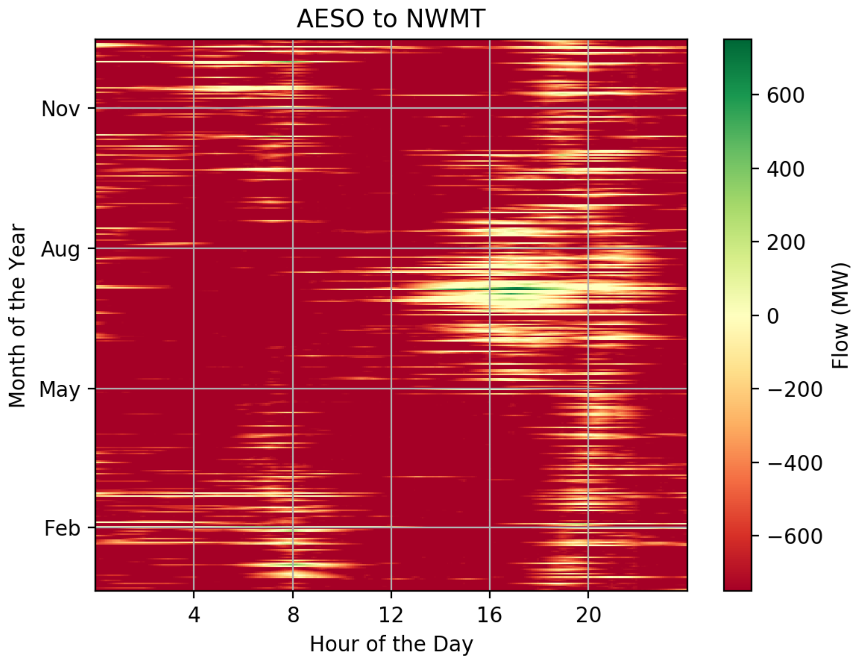

Figure 4.24 shows power flow from Avista Corporation (which services Eastern Washington, Northern Idaho, and parts of Oregon) to British Columbia (BCTC). In this region, the Northwestern US is receiving power from Canada, primarily during the evening hours and summer months.

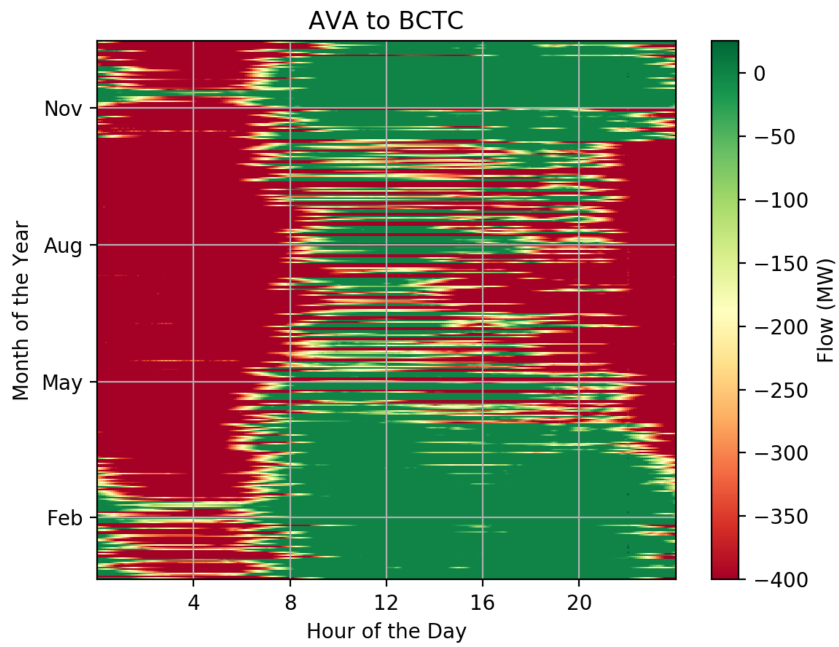

Figure 4.24. Avista Corporation to British Columbia Power Flow

Figure 4.25 shows that power flows between British Columbia (BCTC) and Bonneville Power Administration (BPA) are small. There are brief periods where 500 to 1000 MW are exchanged to accommodate short-term disruptions in one of the two balancing areas.

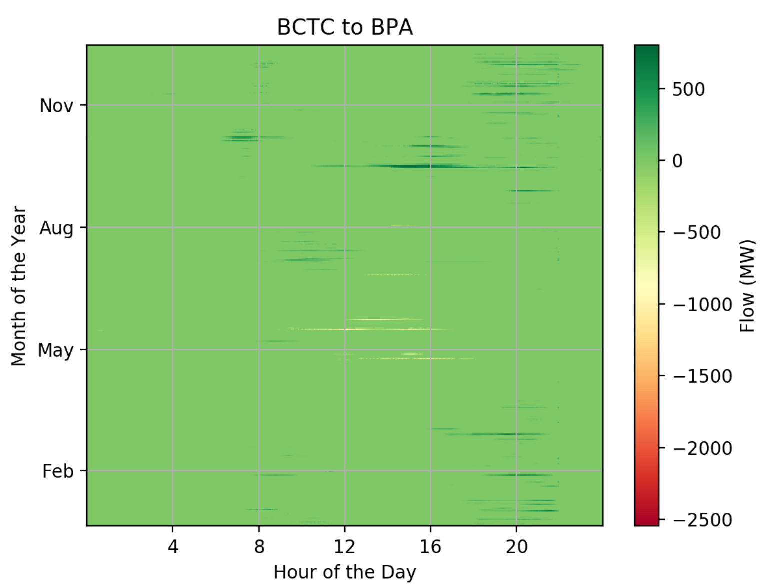

Figure 4.25. British Columbia to Bonneville Power Administration Power Flow

The data in Figure 4.26 are a sum of the three previous charts showing total flow of power from Canada to the US. The US mostly sends power to Canada except during summer peak load hours when flow is reversed.

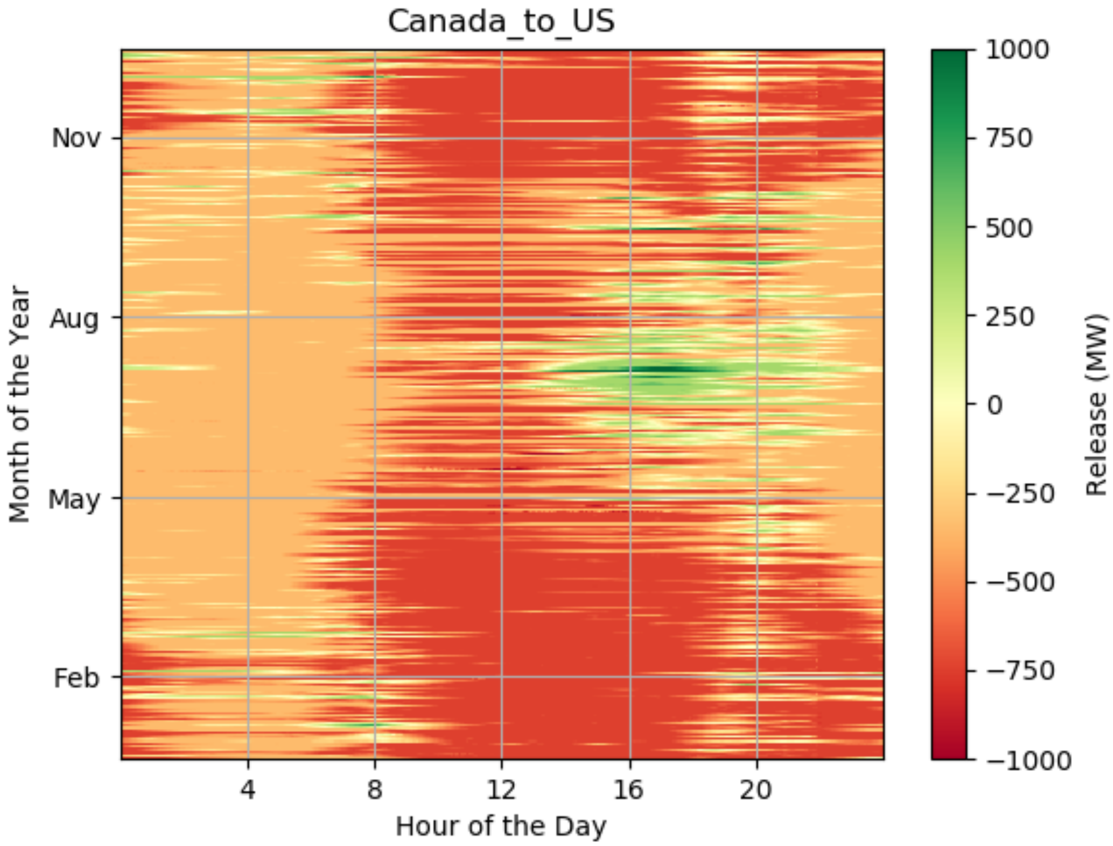

Figure 4.26. Canada to US Aggregated Power Flow

The data in the figures provide metrics that show the magnitude and timing of power shipments between balancing area authorities that can provide cost-effective flexibility services. These shipments inform flexibility demand and supply decisions that both parties to the bilateral transactions are evaluating.

4.3.4.4 Storage

Different storage technologies in different regions of California were also modeled. Charging (inflow) and discharging (outflow) patterns for all hours of the year 2020 simulation are shown in the following graphs.

Figure 4.27 shows charging patterns for compressed air energy storage (CAES) in the PG&E San Francisco Bay Area. As one might expect, charging occurs late at night. Charging also occurs during the winter, spring, and fall months between 11:00 am and 4:00 pm when solar generation is at a maximum. Discharge patterns are shown in Figure 4.28. The systems are discharged during evening peak loads throughout the year. In addition, the systems are discharged during the morning peak load in the winter, spring, and fall. These patterns imply that the batteries are cycled once during the summer months and twice during other times in the year.

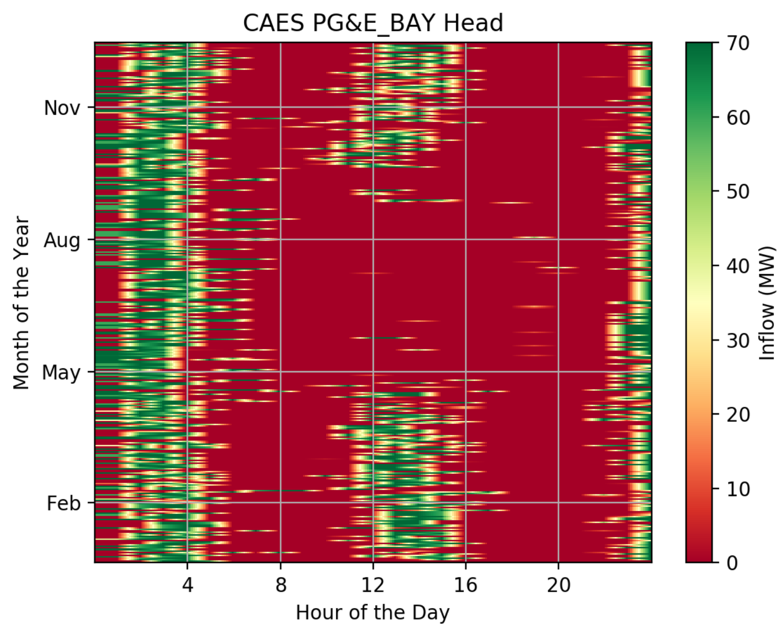

Figure 4.27. Compressed Air Energy Storage Charging Schedule for PG&E Bay Area Service Territory

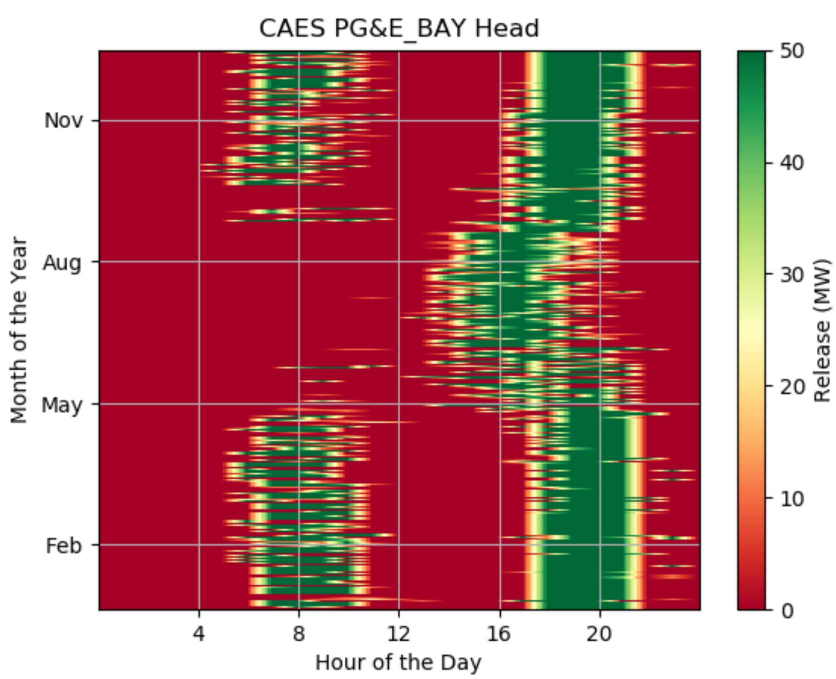

Figure 4.28. Compressed Air Energy Storage Discharging Schedule for PG&E Bay Area Service Territory

Charging and discharging patterns for CAES systems in Southern California Edison's (SCE) service territory are shown in Figure 4.29 and Figure 4.30, respectively. Operations in this area generally follow the same patterns observed in PG&E's service territory.

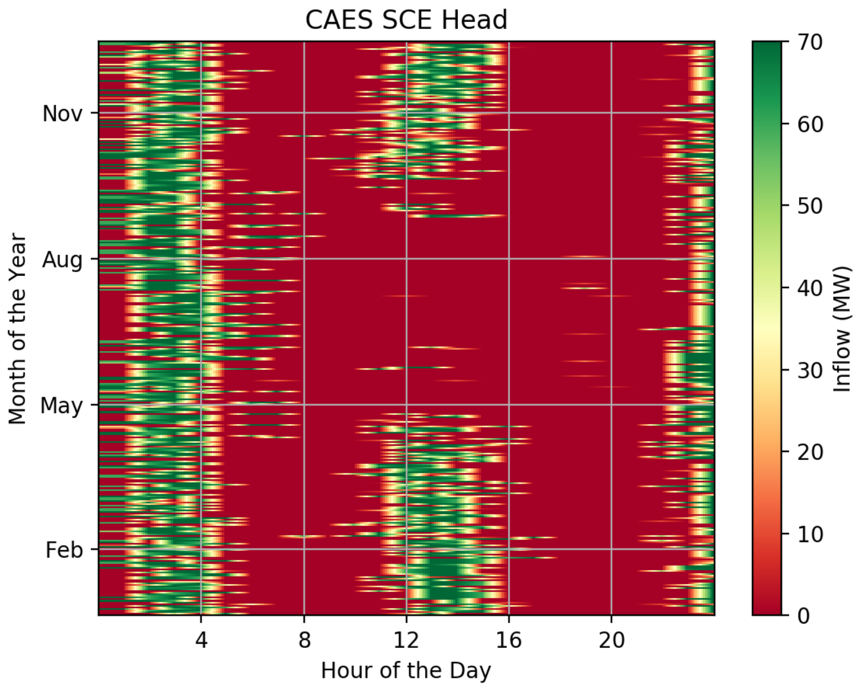

Figure 4.29. Compressed Air Energy Storage Charging Schedule for SCE Service Territory

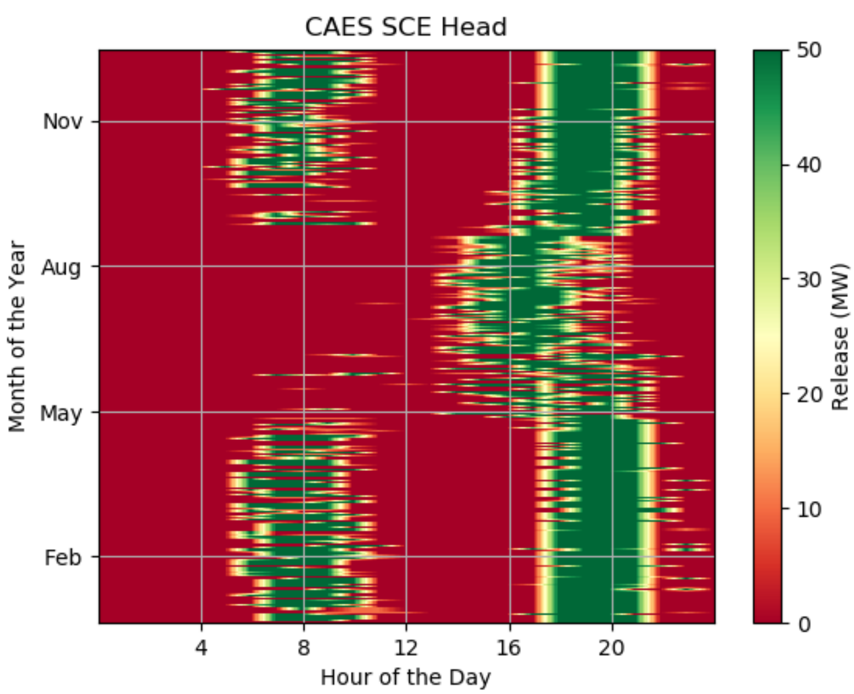

Figure 4.30. Compressed Air Energy Storage Discharging Schedule for SCE Service Territory

Figure 4.31 and Figure 4.32 show lithium ion battery usage in the PG&E San Francisco Bay Area. Charge and discharge times are similar to those observed for CAES systems, but the green regions of high usage are sparser. This is due to the better economics of CAES systems driven by low natural gas prices. In the model, the CAES storage systems were dispatched before the lithium ion battery systems.

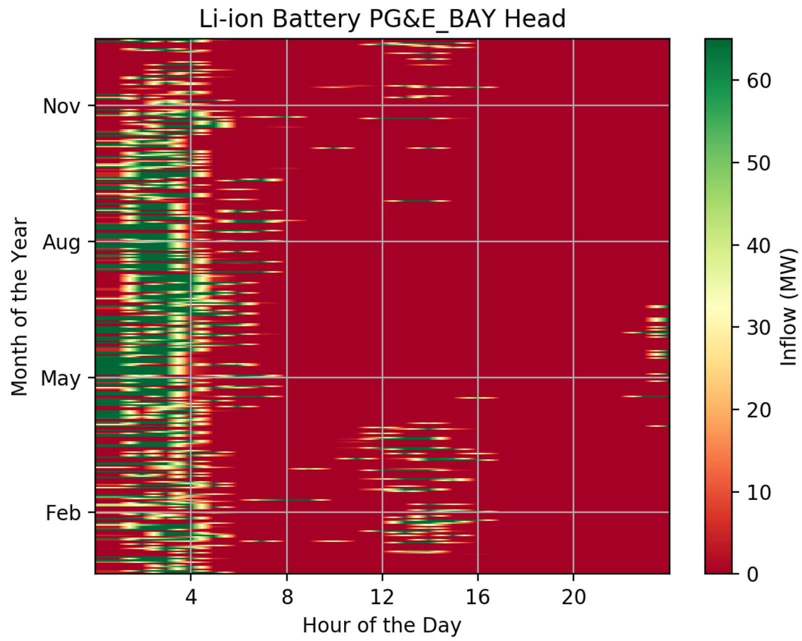

Figure 4.31. Li-Ion Battery Charging Schedule for PG&E Bay Area Service Territory

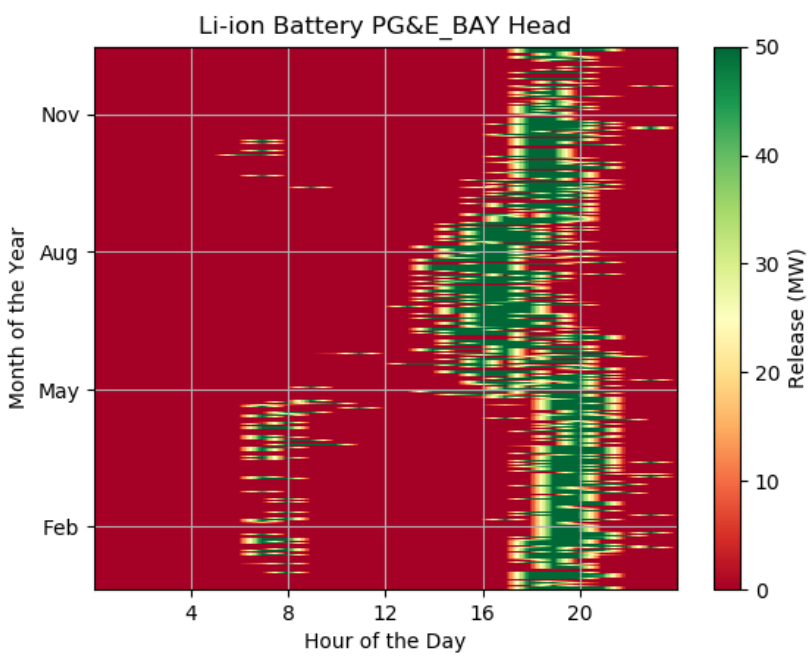

Figure 4.32. Li-Ion Battery Discharging Schedule for PG&E Bay Area Service Territory

The California Central Valley region in PG&E's service territory was also modeled. This is a more rural area with load driven by agricultural production and other industries. Usage patterns are shown in Figure 4.33 and Figure 4.34. Overall, utilization is lower in this region relative to the urbanized San Francisco Bay Area.

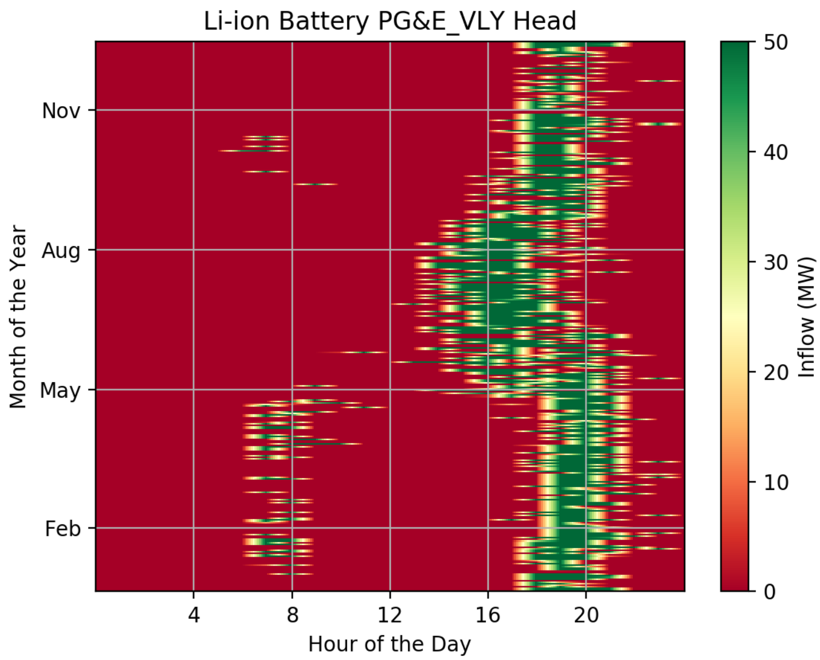

Figure 4.33. Li-Ion Battery Charging Schedule for PG&E Valley Service Territory

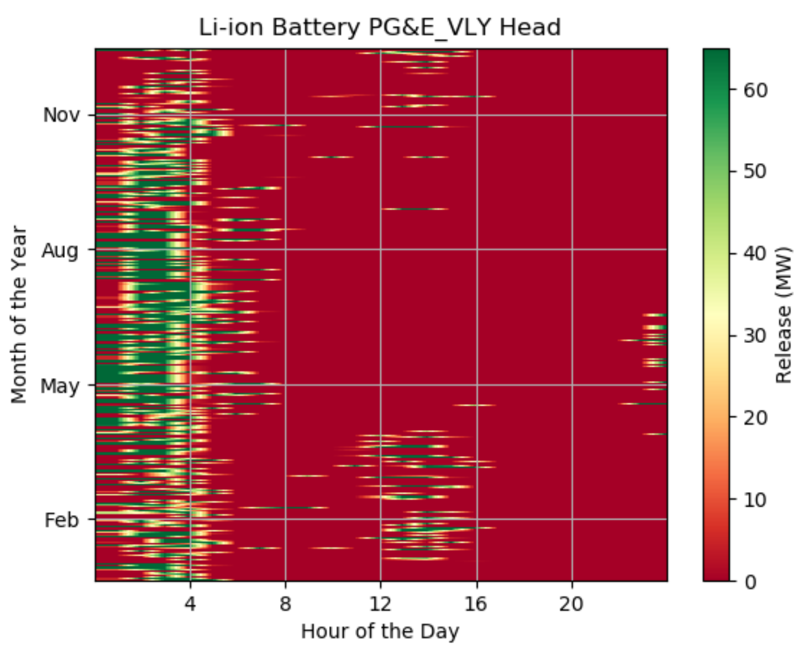

Figure 4.34. Li-Ion Battery Discharging Schedule for PG&E Valley Service Territory

Finally, operation of a large fleet of small, residential lithium ion batteries in the Southern California Edison service territory was also modeled. Charge and discharge patterns are shown in Figure 4.35 and Figure 4.36, respectively. Overall operational patterns are similar to those observed in other areas.

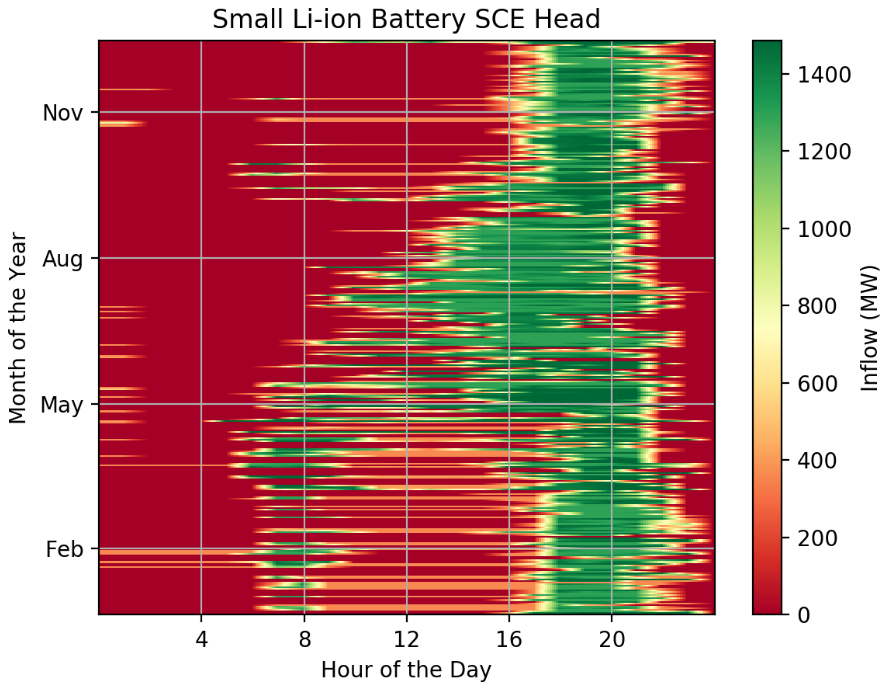

Figure 4.35. Small Li-Ion Battery Charging Schedule for SCE Service Territory

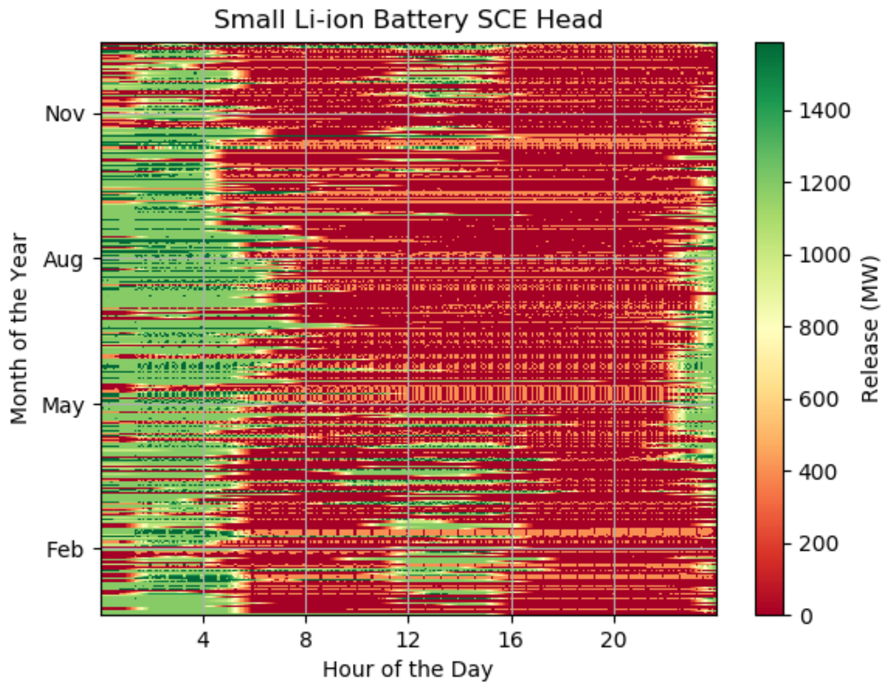

Figure 4.36. Small Li-Ion Battery Discharging Schedule for SCE Service Territory

The data in these figures provide metrics that show the magnitude and timing of cost-effective energy storage and consumption in several California utility service territories. These data inform storage capacity supply decisions.

5.0 Next Steps

Proposed next steps are:

1. Compute leading flexibility metrics using output of more recent production simulation runs of the WECC with more aggressive renewable penetration standards (Alvarez et al. 2017). This study generated results from 88,000 simulations of the test year under a variety of weather conditions, grid configurations, and operating policies.
2. Develop metrics for flexibility demand, supply, and balance in the distribution system. Utilize previously built models and data sets from third parties.
3. Develop flexibility supply metrics that characterize demand response. Utilize results from GMLC project 1.4.2 Grid Services and data from pilot studies conducted in Austin, Texas.

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Appendix A

Feedback from Stakeholders Regarding Year 1 Outcomes

Appendix A

Feedback from Stakeholders Regarding Year 1 Outcomes

This section summarizes the feedback the research team received from domain experts regarding the outcome of the Year 1 flexibility metrics definitions, the relevance to the community's needs, and the overall value for monitoring progress as the grid evolves.

The following reflections stem from a briefing to domain experts who offered to review the team's Year 1 results. The reviewers represented FERC, PG&E, CAISO, and EPRI. The following is a synopsis of the key points made during the 1.5-hour briefing:

- The scope of the flexibility metric development has been limited to the bulk power system. This decision is solely based on the urgency, expressed by regional transmission organizations (RTOs)/ISOs, to better understand the flexibility requirements for addressing the expected increase in generation fluctuations from wind and large solar installations. The flexibility concerns for distribution systems have not risen to the same level of urgency as the concerns mentioned by grid operators of the transmission network. However, with increasing distributed energy resource penetration, flexibility concerns may arise for distribution systems as well. Currently, "hosting capacities" for rooftop PV installations of individual feeders is being used as an indicator to assess the need for feeder upgrades. If and when we reach increasing limitations of hosting capacity, the exploration of flexibility metrics for distribution systems will become more compelling and urgent.
- The current number of flexibility metrics is large. The reviewers thought that the collection of candidate metrics was sufficient, though perhaps a little too large without any guidance as to where and under what circumstance each metric might apply. There was a desire to reduce the large set of metrics to make it more manageable and expressive about what the overarching state of flexibility is. No further guidance was provided by the reviewers as to what a reduced set of metrics may consist of.
- The reduction of the large set of metrics to a few indicators was discussed. Reviewers suggested that one of the overarching metrics for flexibility could be overall system cost or market prices. Lack of flexibility might be reflected in the various product price data (energy, ancillary services), but perhaps also in the uplift fees that reflect "out-of-market" dispatches. Pricing data could be a better indicator for inflexibility than NERC performance characteristics (CSP1 or CSP2) because the markets should resolve best resources for dispatch.
- The role of Production Cost Models (PCMs) in determining flexibility requirements was discussed. Reviewers discussed the role of PCMs as a tool for determining future flexibility requirements under high penetration of renewable generation resources. The determinant for assessing sufficient versus insufficient flexibility was generally some reliability indicators that are commonly used in PCM modeling; that is, the level of unserved energy as a consequence of insufficient ramping capabilities. PCM modeling was also used in cases of hindcasting to find the root causes of, for instance, excessive renewable curtailments, or outages, or other grid conditions indicative of a lack of flexibility.
- The role of statistical analysis to reduce the set of flexibility metrics was discussed. The reviewers indicated that there is value in performing statistical analysis of historical data, both operational and market data, to winnow down the large set of metric candidates. It was suggested that using market price data may be a good starting point for finding correlation with system conditions that may be suggestive of a lack of flexibility. Furthermore, using the amount of hourly curtailments may be a starting point for additional statistical analysis.

- Value of lagging and leading metrics:
  - Lagging flexibility metrics are of interest to regulators and even legislators. System operators also use lagging metrics and underlying historical data to try to identify instances of constrained flexibility and potential sources. Lagging metrics could be used to identify potential market improvements.
  - Leading metrics are important to grid operators for scheduling and operational assessments. Leading metrics are of interest for longer-term adequacy assessments and investment decisions for which the reliability councils and ISO/RTOs are responsible, and for addressing questions regarding how much flexibility we need to support higher levels of renewable generation (e.g., for a high renewable portfolio standard [RPS] scenario).
- Value of flexibility metrics. Reviewers indicated that there would be great value in standardizing the methodology of estimating flexibility metrics across the different RTO/ISO markets; or, at least understanding how each RTO/ISO differs in their methodological approaches.

Appendix B

Metrics Inventory

Appendix B

Metrics Inventory

B.1 Flexibility

B.1.1 Data

	Categorization			Summary											Historical Supporting Data - Lagging Metrics				
Metric #	**Sector**	**Category *(from List)***	**Electric System Infrastructure Component *(from List)***	**Metrics Name**	**Description**	**Motivation**	**Units**	**Metric Type *(from List)***	**Metric Classification *(from List)***	**Metric Use *(from List)***	**Primary User *(from List)***	**Secondary User *(from List - if applicable)***	**Metrics Tense *(Lagging/ Leading)***	**Applicable to Valuation Project *(Yes/No)***	**Data Available? *(Yes/No)***	**Geospatial Resolution *(from List)***	**Temporal Frequency of Data Reporting *(from List)***	**Citation/ Data Source Reference #**	**Potential Issues/ Comments**
1	Electricity	Flexibility	Generation central	System Regulating Capability (TVA)	Ratio of the regulating reserve, demand response, can quick start capacity to the system peak load.	Used to score portfolios of generating resources developed using various strategies and across various portfolios. The system regulating capability measures the ability of the portfolio to respond to load swings.	Normalized	Intensity		Learning, Decision-making, Demonstration	Utility	System Operator/Planner	Leading					[FLEX1]	This is a scoring metric used by TVA in their 2015 Integrated Resource Plan. A lower score is worse, as it indicates less capability to respond to swings. Strategies that emphasized renewables had lower scores, as did strategies with more energy efficiency. They plan to refine it.
2	Electricity	Flexibility	Generation central	Variable Energy Resource Penetration (TVA)	Ratio of the variable resource nameplate capacity to the system peak load.	Measures the amount of variable energy resource included in a portfolio.	Normalized	Intensity		Learning, Demonstration	Utility	System Operator/Planner	Leading					[FLEX1]	This is a reporting (rather than scoring) metric used by TVA in their 2015 Integrated Resource Plan (IRP). A higher value indicates more variable renewables are included in the portfolio.

	Categorization			Summary											Historical Supporting Data - Lagging Metrics				
Metric #	**Sector**	**Category *(from List)***	**Electric System Infrastructure Component *(from List)***	**Metrics Name**	**Description**	**Motivation**	**Units**	**Metric Type *(from List)***	**Metric Classification *(from List)***	**Metric Use *(from List)***	**Primary User *(from List)***	**Secondary User *(from List - if applicable)***	**Metrics Tense *(Lagging/ Leading)***	**Applicable to Valuation Project *(Yes/No)***	**Data Available? *(Yes/No)***	**Geospatial Resolution *(from List)***	**Temporal Frequency of Data Reporting *(from List)***	**Citation/ Data Source Reference #**	**Potential Issues/ Comments**
3	Electricity	Flexibility	Generation central	Flexibility Turndown Factor (TVA)	Ratio of the must run and non-dispatchable energy (wind, solar, and nuclear) to the annual sales.	Measures the ability of the system to serve low load periods.	Normalized	Intensity		Learning, Demonstration	Utility	System Operator/Planner	Leading					[FLEX1]	This is a reporting (rather than scoring) metric used by TVA in their 2015 IRP. A higher score indicates a greater need for dispatchable plants to be able to turn down.
4	Electricity	Flexibility	Generation central	Flexible Resource Indicator (WECC)	Ratio of natural gas-fired combustion turbine nameplate capacity and 15% of hydropower capacity to the nameplate capacity of wind.	Provides a general ratio of the amount of flexible resources typically used for balancing VG to the amount of resource-based variability in the system. Identifies circumstances or scenarios where sufficiency of flexibility might be a concern and require more in-depth examination.	Normalized	Intensity		Learning, Demonstration	System operator/planner		Leading					[FLEX2]	WECC used this metric to highlight scenarios in the transmission planning assessment where additional studies may be needed to assess flexibility.

	Categorization			Summary											Historical Supporting Data - Lagging Metrics				
Metric #	**Sector**	**Category *(from List)***	**Electric System Infrastructure Component *(from List)***	**Metrics Name**	**Description**	**Motivation**	**Units**	**Metric Type *(from List)***	**Metric Classification *(from List)***	**Metric Use *(from List)***	**Primary User *(from List)***	**Secondary User *(from List - if applicable)***	**Metrics Tense *(Lagging/ Leading)***	**Applicable to Valuation Project *(Yes/No)***	**Data Available? *(Yes/No)***	**Geospatial Resolution *(from List)***	**Temporal Frequency of Data Reporting *(from List)***	**Citation/ Data Source Reference #**	**Potential Issues/ Comments**
5	Electricity	Flexibility	Generation central	Periods of Flexibility Deficit (EPRI)	Quantity by which potential demand for flexibility exceeds the potential to supply flexibility (i.e. react to a change in the net load) for any hour.	A post-processing analysis that highlights periods where a system could be at risk of having insufficient flexibility if a rapid change in the net load were to occur. This analysis could be applied to past observed system dispatch outcomes or to simulations of future dispatches.	MW of flexibility deficit in the up or down direction for each hour.	Absolute		Learning	Utility	System Operator/Planner	Lagging or Leading					[FLEX3]	EPRI has a software tool that can be used to calculate the flexibility deficit for any historical dispatch or using any production cost model simulation of future dispatch. ERCOT demonstrated the use of the tool with historical data (2014) and with simulations of the future market.
6	Electricity	Flexibility	Generation central	IRRE	The expected number of observations when a power system cannot cope with the changes in net load, predicted or unpredicted.	This flexibility metric measures, in a probabilistic manner, the ability of a system to use its resources to meet both predicted and unpredicted net load changes, accounting for how the system is operated (including dispatch and reserves).	Number of observations with insufficient ramping.	Absolute		Learning	System operator/planner	Utility	Leading					[FLEX4]	E. Lannoye developed this metric in an IEEE paper; similar to the EPRI approach, albeit more probabilistic.

	Categorization			Summary											Historical Supporting Data - Lagging Metrics				
Metric #	**Sector**	**Category *(from List)***	**Electric System Infrastructure Component *(from List)***	**Metrics Name**	**Description**	**Motivation**	**Units**	**Metric Type *(from List)***	**Metric Classification *(from List)***	**Metric Use *(from List)***	**Primary User *(from List)***	**Secondary User *(from List - if applicable)***	**Metrics Tense *(Lagging/ Leading)***	**Applicable to Valuation Project *(Yes/No)***	**Data Available? *(Yes/No)***	**Geospatial Resolution *(from List)***	**Temporal Frequency of Data Reporting *(from List)***	**Citation/ Data Source Reference #**	**Potential Issues/ Comments**
7	Electricity	Flexibility	Generation central	Flexibility Metric (ISO-NE)	Comparison of the largest variation range (i.e., the flexibility supply) with the target range (the flexibility demand) to reflect excessive availability of the system relative to the target variation range.	They use the metric to create a real-time situation-awareness tool for ISO New England that shows the degree to which flexibility capability exceeds the flexibility need in operational settings looking out over the next few hours. Where flexibility is limited, the operators can use the information to identify corrective actions while many options are still available.	Binary (is there a shortage or not?)	Absolute		Learning, Decision-Making	System operator/planner	Utility	Leading					[FLEX5]	This is a very rigorous definition of flexibility that accounts for the transmission network.
8	Electricity	Flexibility	Generation central	System Flexibility (PSE)	Comparison of the flexibility supply from generating resources (primarily the utilities' share of hydroelectric generating facilities, but also of the simple- and combined-cycle gas-fired units) to the flexibility demand (based on the volatility observed in load,	Process to evaluate the flexibility of a utility's planned system in an integrated resource plan.	Average MW of unmet reserves in hour-ahead balancing and unmet reserves in intra-hour balancing.	Absolute		Learning, Decision-Making	Utility		Leading					[FLEX6]	PSE used this analysis to evaluate their portfolio of resources. They also included an analysis on the impact of adding additional flexible generation on reducing the balancing costs, thus highlighting the economic implications of flexibility.

	Categorization			Summary											Historical Supporting Data - Lagging Metrics				
Metric #	Sector	Category *(from List)*	Electric System Infrastructure Component *(from List)*	Metrics Name	Description	Motivation	Units	Metric Type *(from List)*	Metric Classification *(from List)*	Metric Use *(from List)*	Primary User *(from List)*	Secondary User *(from List - if applicable)*	Metrics Tense *(Lagging/ Leading)*	Applicable to Valuation Project *(Yes/No)*	Data Available? *(Yes/No)*	Geospatial Resolution *(from List)*	Temporal Frequency of Data Reporting *(from List)*	Citation/ Data Source Reference #	Potential Issues/ Comments
					generation and transmission curtailments, and the uncertainty inherent in predicting loads, wind generation and unexpected events).														
9	Electricity	Flexibility	Generation central	Net Demand Ramping Variability (NERC ERSTF)	Historical and projected maximum one-hour-up, one-hour-down, three-hour-up, and three-hour-down net demand ramps (actual load less production from variable energy resources VERs) using one-minute data.	Measures the maximum net demand variability faced by a balancing authority. Ultimately, the balancing authority (BA) needs to have adequate resources available to meet the expected demand variability. Tracking this metric allows for early identification of potential areas for further analysis.	MW of net demand variability.	Absolute		Learning	System operator/planner	Utility	Lagging or Leading					[FLEX7]	This is Measure 6 of the most important essential reliability services identified by NERC's Essential Reliability Services Task Force.

	Categorization			Summary											Historical Supporting Data - Lagging Metrics				
Metric #	**Sector**	**Category *(from List)***	**Electric System Infrastructure Component *(from List)***	**Metrics Name**	**Description**	**Motivation**	**Units**	**Metric Type *(from List)***	**Metric Classification *(from List)***	**Metric Use *(from List)***	**Primary User *(from List)***	**Secondary User *(from List - if applicable)***	**Metrics Tense *(Lagging/ Leading)***	**Applicable to Valuation Project *(Yes/No)***	**Data Available? *(Yes/No)***	**Geospatial Resolution *(from List)***	**Temporal Frequency of Data Reporting *(from List)***	**Citation/ Data Source Reference #**	**Potential Issues/ Comments**
10	Electricity	Flexibility	Generation central	LOLE_flex (LOLE_multi_hour and LOLE_intra_hour)	Attributes loss-of-load events during times when generation capacity was not limited (i.e. there was excess capacity available, but it could not be accessed due to flexibility constraints) to either multi-hour or intra-hour flexibility deficits.	Expand the traditional definition of LOLE to account for operating flexibility in order to answer the question: How much capacity and operating flexibility is needed for a power system to meet the 1 day in 10 years LOLE reliability standard?	Days with loss-of-load in 10 years.	Absolute		Learning, Decision-Making	System operator/planner	Utility	Leading					[FLEX8]	This expanded definition of LOLE was developed in the CES-21 project and implemented in a commercial production cost model by Astrape Corp.
11	Electricity	Flexibility	Generation central	Binding flexibility ratio	Measures the ratio of the flexibility demand to the flexibility supply in the operational time interval where flexibility is most binding.	To better gauge the flexibility of planned resource portfolios, we developed a way to measure, at a screening level, the overall flexibility of a portfolio.	Normalized	Intensity		Learning	Utility	State Regulator	Leading					[FLEX9]	This is a screening-level metric that was applied to resource portfolios included in the Resource Planning Portal, a database of IRPs from utilities in the Western US.
12	Electricity	Flexibility	Generation central	Flexible Capacity Need (CAISO)	A monthly measure of the maximum 3-hour contiguous ramp in the net load, plus the larger of the most severe single contingency or 3.5% of the monthly peak load.	Part of an annual flexible capacity technical study to determine the flexible capacity needed to help ensure the system reliability. The flexible capacity need is then allocated to LSEs.	MW of flexible capacity.	Absolute		Decision-Making, Accountability	System operator/planner	State Regulator	Leading					[FLEX10]	The CAISO calculates the flexible capacity need on an annual basis for the CPUC and for its Flexible Resource Must Offer Obligation.

	Categorization			Summary											Historical Supporting Data - Lagging Metrics				
Metric #	**Sector**	**Category *(from List)***	**Electric System Infrastructure Component *(from List)***	**Metrics Name**	**Description**	**Motivation**	**Units**	**Metric Type *(from List)***	**Metric Classification *(from List)***	**Metric Use *(from List)***	**Primary User *(from List)***	**Secondary User *(from List - if applicable)***	**Metrics Tense *(Lagging/ Leading)***	**Applicable to Valuation Project *(Yes/No)***	**Data Available? *(Yes/No)***	**Geospatial Resolution *(from List)***	**Temporal Frequency of Data Reporting *(from List)***	**Citation/ Data Source Reference #**	**Potential Issues/ Comments**
13	Electricity	Flexibility	Generation central	Renewable curtailment	Percentage of the available renewable energy that must be curtailed due to flexibility limitations.	Highlight the consequences of insufficient flexibility.	Normalized	Absolute		Learning, Decision-Making	System operator/planner	State Regulator	Lagging or Leading					[FLEX11]	Numerous studies have focused on curtailment of RE as a sign of inflexibility. E3's study is a particularly good example.
14	Electricity	Flexibility	Generation central (RTO, ISOs)	Percent of unit-hours mitigated	Percentage of unit-hours that prices were set at the mitigated price on an annual basis.	High values of this metric may be due to a lack of flexibility in the system. CAISO reported the highest percentage of mitigated hours in this report. CAISO has large intermittent renewable fleet requiring flexibility operations.	Normalized	Absolute		Learning, Decision-Making	System operator/planner	State Regulator	Lagging or Leading					FERC Common Metrics Report	Price mitigation may be due to component outages or other factors not related to flexibility. Research is needed to de-convolve these factors.
15	Electricity	Flexibility	Generation central (RTO, ISOs)	Demand response (DR)	DR as a % of total installed capacity.	Provides an indication of the contribution of DR to maintaining the short and long-term reliability.	Normalized	Absolute		Learning, Decision-Making	System operator/planner	State Regulator	Lagging or Leading					FERC Common Metrics Report	DR usage, rather than installed capacity, would be another useful metric.

	Categorization			Summary											Historical Supporting Data - Lagging Metrics				
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16	Electricity	Flexibility	Generation central (RTO, ISOs)	Control Performance Standards (CPS1, CPS2, BAAL)	Control performance standards measure a balancing area's Area Control Error, which indicates how well the system operators maintain a balance between supply and demand. BAs need to meet NERC-mandated performance standards to show that they are maintaining an adequate balance.	Decreases in control performance indicate that the system operator is not maintaining a balance between supply and demand. This can be due, in part, to insufficient flexibility.	Normalized	Absolute		Accountability	System operator/planner	Federal Regulator (FERC/NERC)	Lagging		Yes	RTO/Balancing Authority	Monthly	NERC Standards	Poor performance could be due to other factors besides lack of flexibility.

B.1.2 References

Citation/ Data Source Ref #	Citation/Data Source
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FLEX2	WECC (Western Electricity Coordinating Council). 2013. 2013 Interconnection-wide Plan: Plan Summary. Salt Lake City: WECC. https://www.wecc.biz/Reliability/2013Plan_PlanSummary.pdf.
FLEX3	Electric Power Research Institute (EPRI). 2014. “Metrics for Quantifying Flexibility in Power System Planning.” Palo Alto, CA: Electric Power Research Institute. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002004243.
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FLEX6	Puget Sound Energy. 2015. “2015 Integrated Resource Plan: Appendix H - Operational Flexibility.” http://pse.com/aboutpse/EnergySupply/Pages/Resource-Planning.aspx.
FLEX7	North American Electric Reliability Corporation (NERC). 2015. “Essential Reliability Services Task Force Measures Framework Report.” Atlanta, GA: North American Electric Reliability Corporation. http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf.
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FLEX11	Energy and Environmental Economics, Inc. 2015. “Western Interconnection Flexibility Assessment.” San Francisco, CA. https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/WECC_Flexibility_Assessment_ExecSumm_2016-01-11.pdf.

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