Grid Modernization: Metrics Analysis (GMLC1.1)

Reference Document, Version 2.1

May 2017

Grid Modernization Laboratory Consortium

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Executive Summary

This report is version 2.1 of the Reference Document for the Grid Modernization Laboratory Consortium (GMLC) Metrics Analysis project, generally referred to by its initials, GMLC1.1. It documents the progress made after Year 1 of conducting the project to select, describe, and define metrics for the purpose of monitoring and tracking system properties of the electric infrastructure as it evolves over time. The Reference Document covers the following six topic areas for characterizing the U.S. electric grid:

Reliability	Sustainability
Resilience	Affordability
Flexibility	Security

These six topics were selected by the U.S. Department of Energy (DOE) as a core set of electric infrastructure metrics areas that are important to track (DOE 2015a). No claim has been made about the completeness of this set, but it appears that the six areas are a reasonable starting point for a metrics analysis.

The expected outcome of this 3-year GMLC Metrics Analysis project is to enhance the existing state of metrics to 1) provide federal, state, and municipal regulators more comprehensive information about the current state of the electricity system to measure impacts of grid modernization and technology deployment, 2) support self-assessment by utility organizations across multiple attributes of grid operations, and 3) enable DOE to better set priorities on modernization research and development (R&D).

To achieve this outcome, the project team adopted the following approach: 1) engage with key stakeholders and data partners in each of the six metrics areas to understand industry needs, data availability, access to data, and potential use of metrics and concerns about misuse of metrics results; 2) define new metrics or enhancements to existing metrics; 3) validate metrics in real-world conditions; and 4) work on the adoption of metrics through standards bodies or use by key data partners.

Definitions of Metrics

The six metric categories explored in this project are described in Table 1.1.

Table ES.1. Metrics Descriptions and Focus Areas

Attribute Definition	Existing Metrics	Metrics Being Refined or Developed
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 interruptions in the delivery of electricity in sufficient quantities and of sufficient quality to meet electricity users' needs for (or	Existing reliability metrics (e.g., SAIDI and SAIFI), though mature, pertain primarily to distribution networks. They gauge the frequency and duration of outages averaged over all customers within a given service territory over a specified time period. This	At the distribution level, the GMLC analysts are developing more granular, value-based metrics that will enable utilities to estimate the likely costs to customers of outages in specific locations so that investment dollars can be allocated to reduce the likelihood of the most costly interruptions. These metrics will be developed and demonstrated through a partnership with the American Public Power Association.

Attribute Definition	Existing Metrics	Metrics Being Refined or Developed
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.	approach masks the wide variance among outages in terms of size, duration, and economic impact on customers.	At the bulk power level, the GMLC team will work with NERC on new transmission metrics to gauge the overall health (in terms of reliability) of three North American interconnections.
Resilience: **"**The ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents."[1]	At present, widely-accepted metrics for resiliency do not exist. As noted above, existing reliability metrics do not focus on the impacts resulting from individual events or on individual critical sectors, especially resilience events, which are infrequent, yet have large consequences.	GMLC analysts are piloting new metrics through case studies of hypothetical resilience conducted with industry stakeholders (e.g., City of New Orleans facing another Category 5 hurricane) *Direct metrics* Electrical Service: Cumulative customer-hours of outages; Cumulative customer energy demand not served; Average number (or percentage) of customers experiencing an outage during a specified time period Critical Electrical Service: Cumulative critical customer-hours of outages; Critical customer energy demand not served; Average number (or percentage) of critical loads that experience an outage Restoration: Time to recovery; Cost of recovery Monetary: Loss of utility revenue; Cost of grid damages (e.g., repair or replace lines, transformers); Cost of recovery; Avoided outage cost *Indirect metrics* Community: Critical services

[1] Source: Presidential Policy Directive 21 [PPD-21, Obama 2013]

Attribute Definition	Existing Metrics	Metrics Being Refined or Developed
		Function without power (e.g., hospitals, fire stations, police stations)
Flexibility: The ability of the grid (or a portion of it) to respond to future uncertainties that stress the system in the short term and may require the system to adapt over the long term. Two perspectives: 1) from an operational viewpoint, the agility of the electrical network in adjusting to known or unforeseen short-term changes, such as abrupt changes in load conditions or sharp ramps due to errors in renewable generation forecasts; and 2) from a strategic investment perspective, the ability to respond to major regulatory and policy changes and technological breakthroughs without incurring stranded assets.	At present, widely-accepted metrics for flexibility do not exist.	Grid operators have told GMLC analysts that the flexibility metrics they need most urgently pertain to coping with short-term fluctuations in the availability of generation from wind and utility-scale solar facilities. The analysts are evaluating more than 20 separate metrics that could be used to either understand quickly the nature of a given fluctuation or to estimate the likely effectiveness of alternative options for dealing with a particular fluctuation. The GMLC analysts are concentrating on this bulk-power problem and have deferred for a later time the issues of how to measure and respond to short-term flexibility challenges at the distribution level, and how to build more flexibility into long-term system plans.
Sustainability: The provision of electric services to customers while minimizing negative impacts on humans and the natural environment. This attribute may be more broadly defined as including three pillars: environmental, social, and economic. GMLC is focusing first on the environmental pillar.	A wealth of existing and mature metrics exists, particularly regarding electricity-related environmental impacts. However, most of these metrics pertain to "lagging" indicators, as opposed to metrics that would aid in predicting likely future performance.	The GMLC analysts are focusing first on how to aid stakeholders in making better use of the available information related to greenhouse gas (GHG) emissions, including identification of current gaps in available information (e.g. emissions from distributed generation). In the second year of this three-year study, the GMLC analysts will develop a new metric to better quantify the relationship between power sector water use and water availability in affected areas.
Affordability: The ability of the system to provide electric services at a cost that does not exceed customers' willingness and ability to pay for those services.	Several mature metrics exist pertaining to the cost-effectiveness of alternative investments in specific technologies, services, practices, or regulations. Examples include calculation of the levelized cost of electricity (LCOE) from new or existing generators, and the internal rate of return (IRR) for	The GMLC analysts are focusing primarily on demonstrating the applicability of customer cost-burden metrics to investment-related options that are evaluated at the utility, state, and national levels. They are also collaborating with another team of GMLC analysts to demonstrate the value of cost-burden metrics in the conduct of the Alaska Microgrid Project, which is designing renewable-based microgrids for two remote Alaskan villages. The purpose

Attribute Definition	Existing Metrics	Metrics Being Refined or Developed
	many kinds of grid-related investments or combinations of them. Metrics are evolving but are not yet widely accepted for gauging the relative size of the "cost burden" that paying for electricity services represents for customers. Most work in this area has focused on low-income residential customers. Very little work has been done pertaining to cost burden for commercial and industrial customers.	of the microgrids is to reduce the extreme cost of providing electricity services to these communities using petroleum-based fuels delivered by aircraft.
Security: The ability to resist external disruptions to the energy supply infrastructure caused by intentional physical or cyber attacks or by limited access to critical materials from potentially hostile countries. GMLC is focusing first on external disruptions to electricity supply infrastructure.	Although a variety of metrics have been proposed, at present widely-accepted metrics for security do not exist. Development and application of metrics for this attribute is difficult because there are no actuarial tables that can tell what adversaries are likely to do, how often they will do it, and how much it will cost the electricity sector when they do it. Further, the subject does not lend itself to modeling because of the large number of unknowns that would have to be estimated and the large margin of error associated with those unknowns.	The Department of Homeland Security (DHS) has developed an Infrastructure Survey Tool (IST) that can be used to collect physical security information pertaining to a given facility. The information thus gathered can then be compiled into a metric called the Protective Measures Index (PMI). The IST/PMI method is applicable to many kinds of energy facilities. GMLC analysts are revising and refining the IST/PMI method to make it more electricity specific. They are demonstrating the modified method with electric-sector organizations (e.g., Commonwealth Edison) through field tests. Note that this effort pertains only to assessing the physical security of grid facilities. The GMLC analysts will address cyber security in a subsequent stage of this three-year project.

Stakeholder Engagement

Throughout the project, input and feedback are sought out from stakeholders. Key national organizations in the electric industry were identified as Working Partners at the inception of the project and engaged to provide both strategic and technical input to the project as a whole. 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, but not limited to, the beginning and scoping stages of the effort and then to more formally review the content in this document at the end of Year 1.

The project team engaged with, received feedback from, and in some cases, formed a partnership with the following entities:

Reliability:	North American Electric Reliability Corporation (NERC), Institute of Electrical and Electronics Engineers (IEEE), American Public Power Association (APPA),
Resilience:	DOE/Office of Energy Policy and Systems Analysis (DOE/EPSA), U.S. Department of Homeland Security (DHS), City of New Orleans, PJM Interconnection, Electric Power Research Institute (EPRI)
Flexibility:	Federal Energy Regulatory Commission (FERC), Pacific Gas and Electric Company (PG&E), California Independent System Operator (CAISO), EPRI, Electric Reliability Council of Texas, Inc. (ERCOT)
Sustainability:	U.S. Environmental Protection Agency (EPA), Energy Information Administration (EIA), Arizona State University National Resources Research Institute (NRRI), Sustainability Accounting Standards Board (SASB)
Affordability:	EPRI, Minnesota Public Utilities Commission (PUC), Colorado State Energy Office, Washington State Utilities and Transportation Commission (UTC), Nation Association of Regulatory Utility Commissioners (NARUC), Alaska Energy Authority
Security:	DHS, EPRI, National Association of State Energy Officials (NASEO), Edison Electric Institute (EEI), Exelon Corporation.

Below is a summary of the feedback from partners regarding the value of the specific metrics development.

New Metrics Development

Definition

Metrics are discussed by their ability to characterize system properties measured in the past (*lagging* metrics) as well as metrics that represent the system's ability to respond to challenges in the future (*leading* metrics).

Reliability

Reliability refers to maintaining the delivery of electric power to customers in the face of routine uncertainty in operating conditions. For utility distribution systems, measuring reliability focuses on interruption in 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.

GMLC1.1 focuses on the following three thrusts within the reliability metrics area:

- Improving distribution system metrics
- Improving transmission system metrics
- Probabilistic enhancement of transmission planning metrics.

Improvements in reliability metric designs are needed to better link metrics to the value of reliability; e.g., the economic costs borne by customers (and utilities) when power is interrupted. Examining these costs involves analyzing information on individual interruptions that is more granular than the information summarized in traditional metrics for annual reliability performance. That is, information is needed on which customers have lost power and for how long. The utilization of this kind of information is essential for introducing economic considerations into grid modernization decisions, so that decision-makers can determine how much improving reliability is worth to a utility, its customers, and society at large.

In addition, research into new metrics is needed. For example, transmission metrics for the overall *health* (from a reliability standpoint) of the three U.S. Interconnections each taken as a whole, have only recently been formulated by NERC's Performance Analysis Subcommittee. Research is needed to help make them even more useful in guiding public and private decision-making.

Currently, the project is working on the improvement of distribution system metrics. The remaining two thrusts are planned activities for Years 2 and 3.

Existing, lagging metrics of distribution reliability (e.g., SAIDI and SAIFI) represent aggregations of interruptions averaged over all customers within a service territory. Consequently, they suppress information that is of growing importance for supporting improvements in the planning and operation of distribution systems. This information, which utilities already collect, involves assessing which *types* of customers (residential, commercial, industrial) have experienced a power interruption and for how long in order to understand the economic costs that power interruptions impose on them. This task is being conducted in partnership with the American Public Power Association. It will develop new metrics that enable direct consideration of the cost of power interruptions to customers that will support future distribution system planning and operating decisions.

Resilience

The Presidential Policy Directive 21 [PPD-21] (Obama 2013) asserts the following definition of resilience:

> The term 'resilience' means the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents.

PPD-21 establishes a national policy on critical infrastructure resilience; additionally, PPD-21's resilience definition is consistent with most other proposed definitions (e.g., Biringer et al. 2013).

The project has developed a set of grid resilience metrics and a process for calculating them. The metrics and process have been developed to accomplish the following:

- Help utilities better plan for and respond to low-probability, high-consequence disruptive events that are not currently addressed in reliability metrics and analyses.
- Provide an effective, precise, and consistent means for utilities and regulators to communicate about resilience issues.

The proposed resilience metrics are *leading* indicators with a forward look at estimating or projecting the resilience of the electric infrastructure given a certain threat scenario.

The GMLC1.1 team recommends that grid resilience metrics be consequence-based and, to the extent possible, they should be reflective of the inherent uncertainties that drive response and planning activities.

Table ES.2 lists example consequence categories to serve as the basis for resilience metrics. All of the consequence categories are measured for the defined system specifications and therefore may be measured across spatial (geographical) and temporal (duration) dimensions.

Table ES.2. Examples of consequence categories for consideration in grid resilience metric development.

Consequence Category	Resilience Metric
Direct	
Electrical Service	Cumulative customer-hours of outages Cumulative customer energy demand not served Average number (or percentage) of customers experiencing an outage during a specified time period
Critical Electrical Service	Cumulative critical customer-hours of outages Critical customer energy demand not served Average number (or percentage) of critical loads that experience an outage
Restoration	Time to recovery Cost of recovery
Monetary	Loss of utility revenue Cost of grid damages (e.g., repair or replace lines, transformers) Cost of recovery Avoided outage cost
Indirect	
Community Function	Critical services without power (e.g., hospitals, fire stations, police stations) Critical services without power for more than *N* hours (where backup power exists by outage exceeds fuel supply, i.e., *N* > hours of backup fuel requirement)
Monetary	Loss of assets and perishables Business interruption costs Impact on Gross Municipal Product (GMP) or Gross Regional Product (GRP)
Other critical assets	Key production facilities without power Key military facilities without power

The project team recommends the following Resilience Analysis Process (RAP), originally developed by Watson et al. (2015) for the 2015 Quadrennial Energy Review (QER). The RAP (Figure ES.1) illustrates the seven-step process to be used to help specify resilience objectives for utilities.

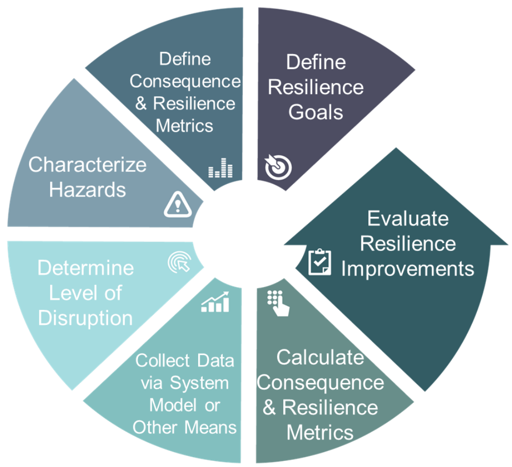

Figure ES.1. The Resilience Analysis Process.

The seven steps are further defined as follows:

1. **Define resilience goals.** The goals lay the foundation for all following steps. For example, the specific goal could be to assess the resilience of a power system to a previous historical event. Alternatively, the goal could be to evaluate possible system improvements. System specification (e.g., geographic boundaries, physical and operational components, relevant time periods, etc.) is required.

2. **Define consequence categories and resilience metrics.** In the context a specified hazard, the RAP measures the resilience of a power system by quantifying the consequences of the hazard for the power system and other infrastructures and communities that depend upon the power system. The consequence categories should reflect the resilience goals. Resilience analyses are not restricted to a single consequence category when developing metrics

3. **Characterize hazards.** Hazard characterization involves the specification of hazards of concern (e.g., hurricane, cyber-attack, etc.). Development of hazard scenarios includes detailing the specific hazard conditions—for instance, frequency or probability of occurrence, the expected hurricane trajectory, wind speeds, regions with storm surge and flooding, landfall location, duration of the event, and other conditions—needed to sufficiently characterize the hazard and its potential impact on the power system.

4. **Determine the level of disruption.** This step specifies the level of damage or stress that grid assets are anticipated to suffer under the specified hazard scenarios. For example, anticipated physical damage (or a range of damage outcomes when incorporating uncertainty) to electric grid assets from a hurricane hazard might include substation X is nonfunctional because of being submerged by sea water, lines Y and Z are blown down due to winds, etc.

5. **Collect consequence data via system model or other means.** Utilities maintain Outage Management Systems (OMSs). These systems are often a rich source of data for resilience analyses, though for the largest events, they often lack details such as the actual locations of the causes of the individual outages and information about system design and condition. When conducting forward-looking analyses, system-level computer models can provide the necessary power disruption estimates. These models use the damage estimates from the previous RAP step as inputs to project how delivery of power will be disrupted. Multiple system models may be required to capture all of the relevant aspects of the complete system.

6. **Calculate consequences and resilience metrics.** Most energy systems provide energy for some larger social purpose (e.g., transportation, healthcare, manufacturing, economic gain). During this

step, outputs from system models are converted to the resilience metrics that were defined during Step 2.

7. **Evaluate resilience improvements.** After developing a baseline for resilience quantification by completing the preceding steps, it is possible and desirable to populate the metrics for a system configuration that is in some way different from the baseline in order to compare which configuration would provide better resilience. This could be a physical change (e.g., adding a redundant power line); a policy change (e.g., allowing the use of stored gas reserves during a disruption); or a procedural change (e.g., turning on or off equipment in advance of a storm).

Some examples from recent Superstorm Sandy were developed to illustrate the application of the RAP process.

Flexibility

Grid flexibility refers to 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. System flexibility can be defined from two perspectives: 1) from an operational viewpoint that considers the agility of the electrical network to adjust to known or unforeseen changes, for instance in load conditions or responding to sharp ramps due to error in renewable generation forecasts; and 2) flexibility from a strategic investment perspective that would consider the flexibility in expansion planning to respond to new regulatory and policy changes as well as to technological breakthroughs without incurring stranded assets. GMLC1.1 focuses on the former—the operational system agility.

The scope of flexibility metric development has been limited to the bulk power system solely based on the urgency that RTOs/Independent System Operators (ISOs) have expressed about needing a better understanding of the flexibility requirements to address expected increases in generation fluctuations from wind and utility-scale 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 photovoltaic installations of individual feeders are 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 the distribution system will become more compelling and urgent.

The motivation to consider operational flexibility stems from the need to accommodate an increasing amount of variable generation from renewable resources (solar, wind), and the fact that an inflexible system can lead to lower reliability, higher costs, and lower sustainability (as expressed in higher emissions or higher consumptive use of water resources). In this report, we focus on both *lagging* and *leading* indicators.

The set of potential new flexibility metrics for use directly in operations and in planning models to estimate future flexibility requirements is large and currently under investigation. They include the following:

1. Loss of load
2. Insufficient ramping
3. Flexibility ratio
4. Wind generation
5. Solar generation fraction
6. Wind generation volatility
7. Solar generation volatility
8. Net load forecasting error
9. Net load factor
10. Maximum ramp rate in net load
11. Maximum ramp capacity
12. Energy storage available
13. Demand response
14. Inter-regional
15. Intra-regional
16. Interruptible tariffs

capability	transfer capability	transfer capability	
17. Renewable curtailment	18. Negative LMP	19. Price spikes	20. Load shedding
21. Operational reserve shortage	22. Control performance (CPSs 1. 2; BAAL)	23. Out-of-market operations	

(BAAL = Balancing Authority area control limit; CPS = Control Performance Standard; LMP = Locational marginal price)

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.

The project team has developed a process to down-select the 23 candidates to a small set. It is recognized that not all metrics are universally applicable for all stakeholders; the metric down-selection process will be driven by stakeholders engaged in the use cases (CAISO, ERCOT, or both). Because CAISO has a significantly larger proportion of solar generation than ERCOT, different flexibility metrics may be chosen for the two ISOs. The ultimate down-selection goal is to identify two or three key leading and lagging metrics for flexibility that include demand, supply, and market efficiency.

Sustainability

Sustainability is often defined as including three pillars: 1) environmental, 2) social, and 3) economic. Given the other categories of metrics defined for the GMLC1.1 project, we define sustainability within GMLC1.1 as *environmental sustainability*. Further, there is a continuum of environmental sustainability metrics from environmental stressors (e.g., greenhouse gas [GHG] emissions) to effects on the environment (e.g., global surface temperature increase) to impacts on humans and the environment (e.g., increased incidence of mosquito-borne diseases). The challenge increases when determining the causality of impacts as one moves from stressors to impacts because multiple causes could be responsible for any given impact (e.g., the health of U.S. citizens). In the first years of the GMLC1.1 project, we will consider environmental stressors, specifically those related to GHG emissions.

This report documents the differences between eight federal electric-sector GHG data products that are publicly available and then discusses how the GHG metrics and reporting procedures may need to be modified to assess changes in environmental sustainability as the grid evolves, particularly, as new distributed resources are deployed.

Table ES.3 summarizes the different federal GHG data products and their constituents.

Table ES.3. Summary of eight federal data products produced by the EPA and the EIA to report GHG emissions from the electric power sector.

Source	Primary Purpose	GHGs Included	Spatial Resolution for Electric-Sector Emissions	Temporal Resolution for Electric-Sector Emissions	Time Range	Reporting Lag
EPA GHG Inventory[(a)]	To develop an economy-wide GHG inventory	CO_2, N_2O, CH_4, HFCs, PFCs, SF_6, NF_3	National	Annually	1990-2014	2 years
EPA GHG Reporting Program[(b)]	To satisfy federal regulations by tracking historical GHG emissions from industrial sectors listed in the Mandatory GHG Reporting Rule, e.g., power plants	CO_2, N_2O, CH_4, HFCs, PFCs, SF_6, NF_3, and other GHGs	Facility	Annually	2010-2015	1 year
EPA eGRID[(c)]	To provide a comprehensive source of historical electricity data to the public	CO_2, N_2O, and CH_4	Unit within facility, entire facility, state, balancing authority, eGRID sub-region, NERC region, and national	Typically every two to three years	1996-2014 (with several gaps)	18 months
EPA Clean Air Markets Program[(d)]	To satisfy federal regulations by tracking historical emissions from power plants	CO_2	Unit within facility, entire facility, state, EPA region, and national (only includes the 48 contiguous states)	Hourly, daily, monthly, quarterly, annually	1980-2016	0-4 months

Table ES.3. (contd)

Source	Primary Purpose	GHGs Included	Spatial Resolution for Electric-Sector Emissions	Temporal Resolution for Electric-Sector Emissions	Time Range	Reporting Lag
EIA Electric Power Annual[(e)]	To provide historical, energy-related information to the public	CO_2	State and national, with facility-level supplements available upon request	Annually	1994-2015	9 months
EIA Monthly Energy Review[(f)]	To provide historical, energy-related information to the public	CO_2	State and national, with facility-level supplements available upon request	Monthly	1973-2017	1 month
EIA Annual Energy Outlook[(g)]	To forecast long-term energy usage	CO_2	Census region and national	Annually	1993-2050	1 year
EIA Short-Term Energy Outlook[(h)]	To forecast short-term energy usage	CO_2	National	Monthly, quarterly, annually	2009-2018	1 month

References: (a) EPA 2015b; (b) EPA 2016e; (c) EPA 2015a; (d) EPA 2016b; (e) EIA 2016b (f) EIA 2016c (g) EIA 2017a; (h) EIA 2017b; (i) EPA 2013

Each of the eight federal electric-sector GHG data products has its own specific purpose, scope, and methods.

At least four of these data products are publicly communicated as representing "electric-sector CO_2 emissions," yet the difference between estimates in a given year is up to 9.4% (Eberle and Heath, paper in preparation).

The absolute differences among these data products are not an indication of uncertainty, but are instead due to legitimate differences in the data products' scopes, purposes, methods, and other factors. For example, the EPA's Clean Air Markets Program (CAMP) data are the lowest because they only account for emissions from units that supply generators above 25 MW, and the EIA's Electric Power Annual (EP Annual) is the highest because it includes emissions from combined heat and power.

Grid modernization may affect the accuracy of established GHG emission data products because the generation mix may change, wherein certain energy sources that emit GHGs that are not currently captured by these metrics could increase. We evaluated the potential coverage gaps that might result for each of the eight federal data products. We found that none of the current data products are currently able to fully allocate the electric-sector portion of CO_2 emissions from several energy sources that are projected to grow in the future: biopower, energy storage, combined heat and power, and small-scale, fossil-fueled distributed generation (Eberle and Heath, paper in preparation). Recommendations will be developed in conjunction with the data product owners that could improve the ability to capture all of the CO_2 emissions from the electric sector in the future, by using methods resilient to anticipated changes in generation sources.

Affordability

The foundational basis for modern grid architecture specification defines affordability as a system quality that "ensures system costs and needs are balanced with the ability of users to pay" (Taft and Becker-

Dippmann 2014). Depending on the stakeholder's objectives, electricity affordability is defined either as the quantification of the cost effectiveness of grid investments or the quantification of the burden on customers of the net costs associated with receiving electric service.

Established metrics for cost-effectiveness are acknowledged and documented, but most recent metric development effort has been devoted to defining metrics designed to inform stakeholders and decision-makers about the customer cost burden imposed by the technology investments to achieve the grid modernization. The cost burden connotation recognizes the notion that while grid technology investments may prove to be cost-effective for their investors, the resulting cost burden on customers may or may not be affordable (i.e. exceeds the customers willingness or ability to pay for).

Electricity affordability implies different things to different stakeholders, as follows:

- residential customer: proportion of electricity costs to household income (cost burden)
- commercial/industrial customer: proportion of electricity costs to gross revenue (cost burden)
- utility commission: the economic effect of provision of electricity on rate payers, underserved markets, and other stakeholders
- utility: the most prudent (economically efficient) resource investments given the constraints
- merchant: economic efficiency, maximizing returns to owners.

This report focuses on the first bullet. The following six metrics were defined for the residential sector:

- Household electricity burden
- Household electricity affordability gap
- Household electricity affordability gap index
- Household electricity affordability headcount index
- Annual average customer cost
- Average customer cost index.

The metrics lend themselves to being compared across different jurisdictions down to the finest level of household income resolution. Figure ES. and Figure ES.3 are representations for state-level and county-level resolutions.

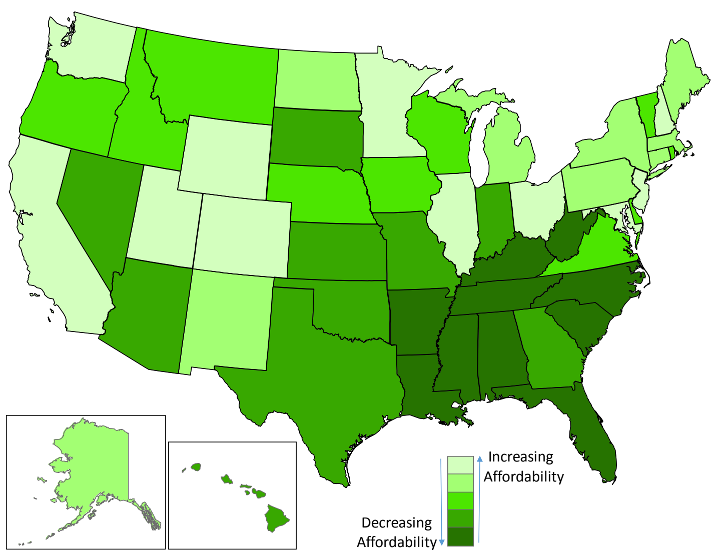

Figure ES.2. 2015 State-level household electricity affordability gap at the 3 percent cost-burden threshold.

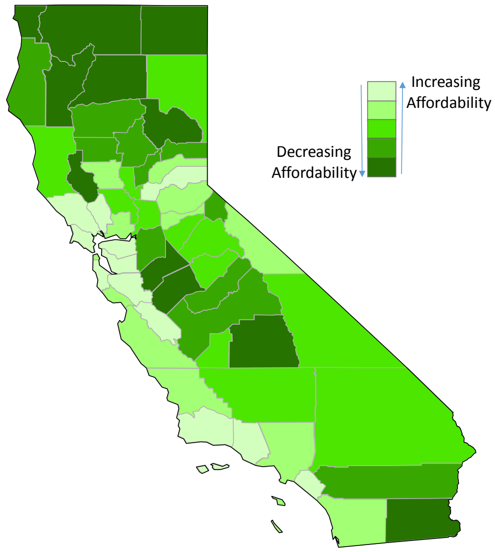

Figure ES.3. 2015 California county-level household electricity affordability gap at the 3 percent cost-burden threshold.

Physical and Cyber Security

Presidential Policy Directive 21 (Obama 2013), "Critical Infrastructure Security and Resilience," defines "security" as "reducing the risk to critical infrastructure by physical means or defense cyber measures to intrusions, attacks, or the effects of natural or man-made disasters."

During its first year, this project focused on physical security. The proposed metric, the "Protective Measures Index" (PMI) has 9 constituents and a process to assign values to the constituents. The PMI structure is shown in Figure ES.4.

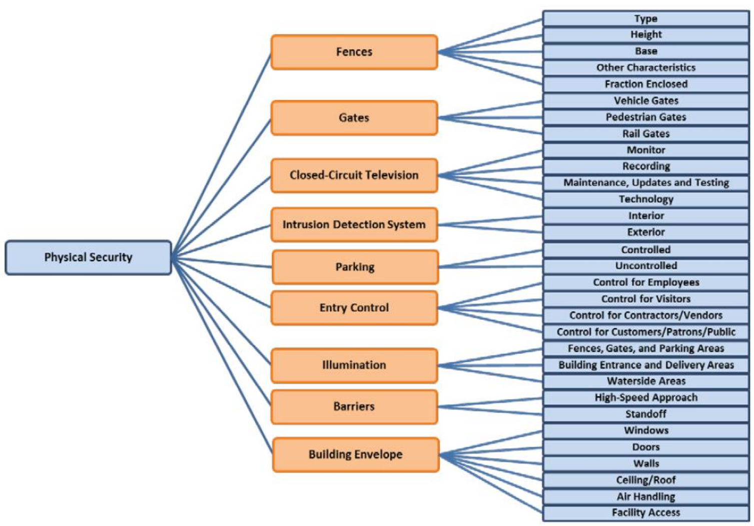

Figure ES.4. Level 1 and 2 subcomponents for physical security (Argonne 2013).

The proposed process is a survey instrument that is designed for utility organizations interested in understanding their physical security posture. The survey instrument guides the analysts through a set of questions to assess the various underlying aspects of PMI and assign numerical or qualitative values. The values are then compared against default values that were derived from DHS surveys for critical infrastructure protection. The outcome of the survey instrument is a ranking that scores relative values against a default value or peer groups. Figure ES. below provides an example of the survey output.

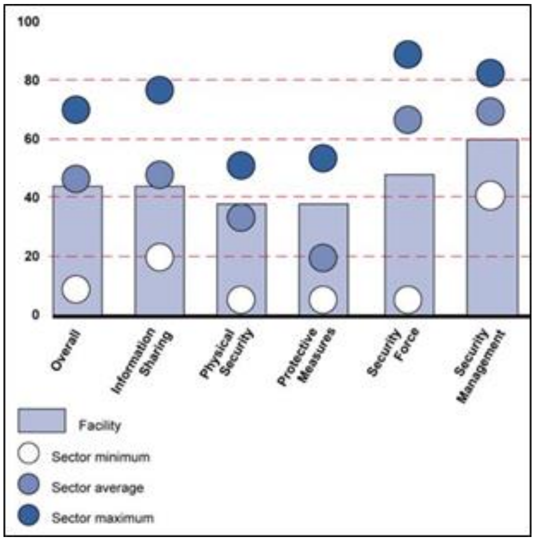

Figure ES.5. Example PMI dashboard for consideration as physical security metrics.

The utility may use the outcome of such surveys to self-assess and identify insufficiencies and how a certain investment could improve the overall PMI value or some of the underlying constituents.

Feedback from Stakeholders on the Metrics Development in Year 1

Between February and March of 2017, the project team conducted a series of 2-hour webinars with a select group of external reviewers, most of whom are project partners, and the DOE program managers assigned to this project (Joseph Paladino, DOE/OE; Guohui Yuan, DOE/Energy Efficiency and Renewable Energy; and David Meyer DOE/OE volunteer). The six metric teams held separate webinars in which they provided an update on metric methodology development and received both directional and technical feedback from these key stakeholders relevant to their work. After a presentation and general discussion, the project team asked a set of specific questions regarding the value and direction of the metrics work. The following section provides a synopsis of the feedback from stakeholders, presented for each of the six metrics areas.

Reliability (Feedback from NERC, APPA)

The following insights were gained for improved transmission system metrics:

- The overall goal of NERC's effort is to try to enhance the metrics that are in its annual State of Reliability report that discuss the Severity Risk Index (SRI). NERC's objective is steady and appropriate integration of new metrics. NERC would like to get to a position where it always has a scale that identifies what needs to be done to increase the reliability of the system. The GMLC 1.1 research will determine how this could be done. The aspiration for this project is to develop a much better understanding of SRI – what it can and cannot tell us about reliability – and to develop new metrics that will complement SRI that will address things that SRI cannot tell us.
- This GMLC 1.1 work effort is likely the start of a long-term collaborative, ground-up exploratory engagement with NERC. This effort is an early-state interaction, in which we are working very collaboratively with the NERC Performance Analysis team to look at data in new ways.

The following insights were gained for improved distribution system metrics:

- APPA has determined that it can be very helpful to its members to have data and tools that can be used to estimate what their customers lose when a service interruption occurs and to inform potential investments to improve system resilience and reduce some amount of outage. APPA has also found that quantifiable research-based estimates of costs related to outages can be extremely meaningful in the public discourse associated with a utility's investments.
- With DOE funding, APPA is building a web-based platform, which will incorporate the Interruption Cost Estimate (ICE) Calculator originally funded by DOE and Lawrence Berkeley National Laboratory. This platform will provide actual outage data collected by utilities and outage cost estimation. One output from the platform will be a ranking of a utility's circuits based on outage cost. The platform is expected to be released by September 2017.
- Our APPA partner sees that his collaboration with DOE over the last half decade is now in a position to legitimately evaluate the efficacy of existing distribution system metrics and to invent new metrics that address any gaps. Based on data provided by utility application of the reliability data collection and analysis platform, APPA and the project team will jointly develop new metrics and assess if they have value.
- The outcomes of this effort are expected to be useful to investor-owned and other utilities beyond APPA's members.

Resilience (Feedback from EPRI, DHS, City of New Orleans, PJM)

- Collaboration with industry. As part of a GMLC regional partnership project with New Orleans, the local utility company (Entergy) is collaborating with DOE laboratories to work on resilience analyses using the approach outlined in this report.
- Value to the community. It is very important from a recovery assistance perspective to have transparent and repeatable methodologies developed that prioritize investment option for improving the resilience of any infrastructure. The approach developed here for the electric grid, will hopefully be employed across multiple sectors so that we understand better how risk affects the resilience of our communities.
- Implementation options for resilience metrics and analysis processes. 1) Regulators could require reporting of resilience assessments, and 2) part of the request for recovery funding from federal sources could require some prior resilience assessment.
- Regarding retrospective versus prospective views of resilience, both PJM and DHS expressed more interest in forward-looking or *leading* indicators that can inform the prioritization of investments for improving resilience.
- The spatial scope of the analysis may dictate the complexity of the resilience assessment. For instance, assessment of cities or metropolitan areas with highly integrated infrastructure systems may require analysis of interactions of failure. However, resilience analyses for an RTO area may focus on the electric grid because the interactions with other infrastructures are weak or loosely coupled.
- It is not clear whether any measure performed to increase resilience will also improve reliability. What has been observed in the aftermath of Hurricane Sandy is that improved resilience increased the flexibility of the grid such that circuits could be sectionalized and switched.

Flexibility (Feedback from FERC, PG&E, CAISO, EPRI)

- The project team compiled a comprehensive list of flexibility metrics based on a literature review and the team's expertise. The reviewers thought that the collection of candidate metrics was sufficient, but that a clearer set could be more useful if supplemented with guidance about where and under what circumstance each metric might apply. The reviewers also acknowledged that the large group of compiled metrics could be further refined into a smaller set of metrics, as some of the metrics seemed to target the same question and some were applicable only to specific market regions. No further suggestions were provided by the reviewers identifying specific metrics to include in a reduced set of metrics.

- 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 of inflexibility than NERC performance characteristics (CSP1 or CSP2) because the markets should resolve best resources for dispatch.
- 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 ISOs/RTOs are responsible, addressing questions of how much flexibility do we need to support higher levels of renewable generation (e.g., for a high renewable portfolio standard scenario).
- The role of statistical analysis to analyze recent events, and in the calculation of lagging metrics, was also discussed. The reviewers indicated that there is value in performing statistical analysis of historical data, both operational and market data, to identify what conditions indicative of lack of flexibility. It was suggested that using market price data may be a good starting point to find any correlations of system conditions and lack of flexibility. Furthermore, using net load, curtailments, self-scheduled generation, or weather data could also inform statistical analysis. However, identifying specific root causes of inflexibility with multiple potential factors can be a data-intensive and challenging process.
- The role of Production Cost Models (PCMs) in determining flexibility requirements was discussed, including the role of PCMs as a tool for determining future flexibility requirements under high penetration of renewable generation resources. A set of reliability indicators is commonly used in PCM modeling to assess sufficient versus insufficient flexibility. One such indicator is the level of unserved energy as a consequence of insufficient ramping capabilities. PCM modeling has also been used in cases of hindcasting to identify the root causes of, for example, excessive renewable curtailments, or outages, or other grid conditions indicative of a lack of flexibility.
- The value of flexibility metrics was considered. Reviewers indicated that there would be great value in standardizing the methodology for estimating flexibility metrics across the different RTO/ISO markets; or, at least, understanding how the RTO/ISO differ in their methodological approaches.

Sustainability (Feedback from EPRI, EPA, EIA, ASU, NRRI, SASB)

- Technical considerations:
  - Reviewers from the Federal organizations that publish the national GHG emissions data products provided some clarifications of the scope and similarity of their products. They indicated that we should mention that the differences among the reported historical emissions for the various products are not due to data uncertainty or variability, but instead relate to the scope of coverage

for each data product, including whether CHP units are included and the generator capacity threshold.

– To expand the GHG emissions reporting to systems with less than 1 MW capacity, one reviewer suggested talking with APX[2]—a provider of technology and service solutions for clients in the energy and environmental markets—about its systems that currently track electricity production from utility-scale plants, to consider if these systems could be augmented to track GHG emissions as well.

- Value of work:
  - Reviewers generally indicated that the work completed so far is valuable for the community, and that work in the sustainability area for utilities should continue. The subset of reviewers involved in providing the national GHG data products did not contribute their views on this topic during the meeting.
  - One reviewer noted that our work on sustainability metrics is also of value to the investment community.
- Reviewers shared their viewpoints for Years 2 and 3 activities. Individual reviewers provided feedback on the options presented but the group did not reach a consensus regarding which topics should be pursued. The following notions were shared:
  - One reviewer noted the importance of water metrics and the value of integrated planning among electric and water utilities.
  - Land use was an interesting and under-analyzed topic.
  - Determining the health impact of criteria pollutants would be valuable but difficult.

<u>Affordability</u> (Feedback from EPRI, MN PUC, Colorado SEO, WA UTC)

- The reviewers provided the following technical comments:
  - A time-trend of the affordability metrics is very useful for assessing changes over time. Perhaps it is more useful/appropriate than the disaggregation across geographic areas that could be influenced by different consumption patterns. For instance, coastal climate zones versus inland zones.
  - Metrics should be defined by seasons, such that consumption for cooling can be isolated from heating end-uses. If we report only annual affordability metrics, the monthly spikes will be reduced in the annualization process, thus underestimating some of the more season-related burdens faced by low-income customers. Addressing seasonality could also support explanation of the consumption-based driver.
  - In addition to the current definition of affordability metrics, the team should consider supplementing the affordability metrics with a $/kWh indicator in order to isolate the rate driver in the affordability values from the consumption-based driver.
  - Income data may be difficult to obtain. Reviewers from Washington and Colorado indicated that the data must be "air-tight" in order to use them in PUC rate proceedings. Utilities would need to be willing to share billing data.

[2] http://www.apx.com/about-apx/

  - Consider whether the affordability metric should include the total or certain portions of the electricity bill. For instance, charges such as transmission and distribution charges, taxes, and demand charges could be separated and not included to make the bill more consumption based.
  - The affordability metrics are very much aligned with the sustainability research EPRI is doing.
- Value of affordability metrics. Affordability metrics are very useful from the reviewers' perspective (primarily from a state perspective), as follows:
  - In Colorado, State Energy Office is interested in this data as they design and execute low-income energy assistance and clean energy programs for residential households.
  - The next customer group for which affordability metrics should be demonstrated is the industrial sector. Industrial customers have been vocal about affordable power concerns via their interveners. Many have threatened states with moving their operations to lower-cost jurisdictions. The challenge is to deal with the very high demand charge not necessarily the usage-based portion of the electricity bill.
  - Reviewers suggested exploring the piloting of this metric development with a specific utility.
- Usability and practicality of applying affordability metrics. A high degree of certainty of the correctness of income data must exist for metrics to be used in a meaningful way at rate proceedings.
  - Perhaps affordability metrics could be used in the context of value-creating attributes or metrics such as resilience. This would allow trade-off analysis to weight affordability versus resilience.
  - A good use of affordability metrics would be to assess investments in residential low-income areas.
  - Utility companies could potentially adopt affordability metrics as a part of their voluntary sustainability reporting.
- Consider what is the best way for the affordability metrics to gain traction in the utility community:
  - via the voluntary route, such that a utility adopts affordability metrics (or a portion of them) as a part of their sustainability reporting based on their own customer bill data (appropriate income data may still be an issue); or
  - via requirements by PUCs for integrated resource planning or in rate proceedings.
- Engage with stakeholders to explore priorities of affordability metrics within the scope of the six metrics categories.

Security (Feedback from DHS, EEI, EPRI, NASEO)

- Technical considerations.
  - The aggregation of multiple indicators representing detailed information about the security posture may not be meaningful as an aggregated indicator masks the higher detailed information. It was suggested to present both the sub-indicators that make up the Protection Measures Index (PMI) as well as the overall PMI.
  - One reviewer suggested providing as much transparency as possible about the underlying assumptions of security measures that were considered in the formulation of the approach and tool development.
- Value of work. Reviewers generally saw that the approach could provide value to an electric utility and regulators and state energy offices in the following respects:

- The metrics approach was viewed as useful for utilities to understand better the relative strength of their physical security posture as well as how they compare against peers.
- The metric approach could be useful for identifying strategies to improve specific physical security practices within their organizations.
- Information derived from the developed approach could be useful for informing rate-recovery decisions with or without consideration of the peer comparisons.
- General concern was expressed about the appropriateness of using the method for peer comparison or even presenting geographically aggregated protected measures index values. This concern in part stemmed from prior experience where some reviewers have seen metrics for other projects be used to create unfair judgments among and between entities that could lead to inappropriate policies.
- The reviewers also recognized challenges associated with protecting the electric utility-completed data.

Acronyms and Abbreviations

°F	degree(s) Fahrenheit
ACE	area control error
ACEEE	American Council for an Energy-Efficient Economy
ACS	American Community Survey
AEO	Annual Energy Outlook (published annually by EIA)
ALE	annualized loss expectancy
AMI	Advanced Metering Infrastructure
AMP	Alaska Microgrid Project
APPA	American Public Power Association
APPRISE	Applied Public Policy Research Institute for Study and Evaluation
APS	Arizona Public Service
ARO	annualized rate of occurrence
ASU	Arizona State University
BAA	balancing authority area
BAAL	Balancing Authority ACE limit
BES	Bulk Electric System
BESSMWG	Bulk Electric System Security Metrics Working Group
C2M2	Cybersecurity Capability Maturity Model
CAMP	(EPA) Clean Air Markets Program
CAISO	California Independent System Operator
CDP	formerly known as "Carbon Disclosure Project" (now simply CDP)
CEMS	continuous emission monitoring system
CH_4	methane
CHP	combined heat and power
CIP	Critical Infrastructure Protection
C-IST	Cyber Infrastructure Survey Tool
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalentCPS1 Control Performance Standard 1
ComEd	Commonwealth Edison
CPS1	Control Performance Standard 1
CPS2	Control Performance Standard 2
CPUC	California Public Utilities Commission
CS&C	(DHS) Office of Cybersecurity & Communications
CSF	Cybersecurity Framework
CVaR	Conditional Value at Risk
CVSS	Common Vulnerability Scoring System

DHS	Department of Homeland Security
DOE	U.S. Department of Energy
ECC	economic carrying capacity
ECIP	Enhanced Critical Infrastructure Protection
EEI	Edison Electric Institute
EERE	DOE Office of Energy Efficiency and Renewable Energy
eGRID	Emissions and Generation Resource Integrated Database
EIA	Energy Information Administration
EP	Electric Power (Annual)
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
EPSA	DOE Office of Energy Policy and Systems Analysis
ERCOT	Electric Reliability Council of Texas, Inc.
ERSTF	(NERC's) Essential Reliability Services Task Force
ES-C2M2	Electricity Subsector Cybersecurity Capability Maturity Model
ES-ISAC	Electricity Sector Information Sharing and Analysis Center
EUE	Expected unserved energy
EWN	energy-water nexus
FERC	Federal Energy Regulatory Commission
FRAC-MOO	flexible resource adequacy criteria-must offer obligation
g	gram(s)
GADS	Generation Availability Data System
GHG	Greenhouse gas
GHGI	Greenhouse Gas Inventory
GHGRP	greenhouse gas reporting program
GMLC	Grid Modernization Laboratory Consortium
GMLC1.1	Grid Modernization Laboratory Consortium Project Metrics Analysis
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
IP	Infrastructure Protection
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated Resource Plan
IRR	internal rate of return
IRRE	Insufficient Ramping Resource Expectation
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
IST	Infrastructure Survey Tool
kV	kilovolt(s)

lb	pound(s)
LBNL	Lawrence Berkeley National Laboratory
LCOE	Levelized cost of electricity
LMP	Location marginal price
LOLE	loss-of-load expectations
LOLP	loss-of-load probability
MER	Monthly Energy Review
MYPP	Multi Year Program Plan
mmBtu	one million British thermal units
MOA	Memorandum of Agreement
MOU	Memorandum of Understanding
MW	megawatt(s)
N_2O	nitrous oxide
NA	not applicable
NARUC	National Association of Regulatory Utility Commissioners
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Corporation
NIPP	National Infrastructure Protection Plan
NIST	National Institute of Standards and Technology
NO_x	nitrogen oxide
NPV	net present value
NREL	National Renewable Energy Laboratory
OE	(DOE) Office of Electricity Delivery and Energy Reliability
OMS	Outage Management System
PCA	power control area
PCE	Power Cost Equalization program
PCII	Protective Critical Infrastructure Information
PCM	Production Cost Model
PG&E	Pacific Gas and Electric Company
PMI	Protective Measures Index
PPD	Presidential Policy Directive
psi	pound(s) per square inch
PUC	Public Utilities Commissions
QER	Quadrennial Energy Review
R&D	research and development
RAP	Resilience Analysis Process
RECS	Residential Energy Consumption Survey
RIST	Rapid Infrastructure Survey Tool

RPS	renewable portfolio standard
RTO	regional transmission organization
RWR	Relative Water Risk
SAIDI	Systems Average Interruption Duration Index
SAIFI	Systems Average Interruption Frequency Index
SASB	Sustainability Accounting and Standards Board
SDG&E	San Diego Gas & Electric Company
SLE	single loss expectancy
SMUD	Sacramento Municipal Utility District
SO_2	sulfur dioxide
SOL	System Operating Limit
SPP	Southwest Power Pool
SRI	solar reflectance index
STEO	Short-Term Energy Outlook
TADS	Transmission Availability Data System
TVA	Tennessee Valley Authority
VaR	Value at Risk
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 (DOEs) 2015 Grid Modernization Initiative Multi Year Program Plan (MYPP), states that as the U.S. 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), other 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 U.S. 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 supports the mission of three DOE Offices' (Office of Electricity Delivery and Energy Reliability (OE), Office of Energy Efficiency and Renewable Energy (EERE), and Office of Energy Policy and Systems Analysis (EPSA)) by revealing and quantifying the current states and its evolution over time of the nation's electric infrastructure.

This project started in April 2016. This report reflects the accomplishments of 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 choose the term metric areas or metric categories. Metrics are physical measurements or economic measures that can be measured or counted. 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 GMLC 1.1
Reliability	Maintain the delivery of electric services to customers in the face of routine uncertainty in operating conditions. For utility <u>distribution systems</u>, measuring reliability focuses on interruption in the delivery of electricity in sufficient quantities and of sufficient quality to meet electricity users' needs for (or applications of) electricity. For the <u>bulk power system</u>, 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 APPA. We are developing new metrics of bulk power system reliability for use in NERC's Annual State of Reliability Report We are demonstrating the use of probabilistic transmission planning metrics with ERCOT and Idaho Power.

Table 1.1. (contd)

Metric Categories	Definitions	Focus Areas under GMLC 1.1
Resiliency	The ability to 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 operational and economic uncertainties that are likely to stress the system or affect costs. Long-term, 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 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 remaining sections below.

1.3 Difference between Reliability and Resilience

Grid resilience metrics should be developed in the context of low-probability, high-consequence potential disruptions. Reliability metrics are defined in the context of outages and disruption under routine or design operating conditions and typically are calculated as aggregated totals over all events – large and small - occurring over the course of a year. Consequently, resilience metrics are more useful for capturing the impacts of singular, infrequent large scale events like hurricanes, earthquakes, and terrorist attacks. The difference in disruption magnitudes leads to a difference in temporal durations. The majority of reliability events are shorter in duration but resilience focuses on individual events that could last days to weeks.

Grid resilience metrics should quantify the consequences that occur as a result of strain on or disruption of the power grid. These consequences can be closely related to grid operations and power delivery (e.g., megawatt-hours of power not delivered as a result of a storm, utility revenue lost, cost of recovery to the utility, etc.) and hence have some similarities to existing reliability metrics. Or they can be measured in terms of greater community impacts such as populations without power (e.g., measured in people-hours), business interruption costs resulting from the power outage, impacts on critical infrastructure functionality, loss of Gross Regional Product, etc. Traditional reliability metrics do not distinguish among the types of customers impacted and aggregate information on the actual duration of interruptions. Currently an hour of power loss to a hospital is equally weighted as an hour of power loss to an empty shed.

Resilience metrics can include secondary impacts to systems when power is lost, such as economic impacts, impacts to critical infrastructure, and effects on local and regional communities. Reliability metrics generally do not include secondary impacts.

Reliability metrics rely on aggregations of historical records (or projected future impacts) to calculate reliability of a system over a period of time, such as a year. Resilience metrics focus on individual events. These events, moreover, are low probability events, thus, historic data may not exist or may be sparse and insufficient to fully characterize resilience. Consequently, resilience metrics are often forward looking and derived with extensive simulations performing what-if analyses.

2.0 Overview of Approach

The GMLC 1.1 project team adopted the following approach: First, metric category teams (Table 2.1) were formed for each of the six categories and led by one of the nine National Laboratories.

Table 2.1. Metric Category Teams

Metric Category	Lead Laboratory (Lead Staff)	Contributing Laboratory
Reliability	Lawrence Berkeley National Laboratory (Joe Eto)	Brookhaven National Laboratory (Meng Yue)
Resilience	Sandia National Laboratories (Eric Vugrin)	
Flexibility	Lawrence Livermore National Laboratory (Tom Edmunds)	Lawrence Berkeley National Laboratory (Andrew Mills) National Renewable Energy Laboratory (Paul Denholm)
Sustainability	National Renewable Energy Laboratory (Garvin Heath)	Lawrence Berkeley National Laboratory (Dev Millstein)
Affordability	Pacific Northwest National Laboratory (Dave Anderson)	Oak Ridge National Laboratory (Stacy Powell)
Security	Argonne National Laboratory (Steve Folga and Angeli Tompkins)	

Then, each metric category team developed a landscape of existing metrics (see Appendix A Metrics Inventory), and this inventory was used to identify opportunities for new metrics and metrics enhancements. Metric teams engaged with potential users and other key stakeholders, including data partners, in each of the six metrics areas to understand stakeholder needs, supporting data availability, the likely application of the metrics, and any potential sensitivities related to public use of the metrics. The key work scope for Year 1 activities included: (1) identification of focus for metrics development and (2) first definitions of new and enhanced metrics, and (3) validation of metrics selection by stakeholders. This report reflects the outcomes of the Year 1 activities.

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 and successfully tested and accepted by a broad range of electric system stakeholders via GMLC 1.1.

Years 2 and 3 of the project will focus on validating metric methodologies by applying them to real-world situations with electric sector partners and also establishing partnerships with key data providers, including federal and state agencies, and regional entities that could potentially help institutionalize the final products and results of GMLC 1.1. This approach is described in Figure 2.1.

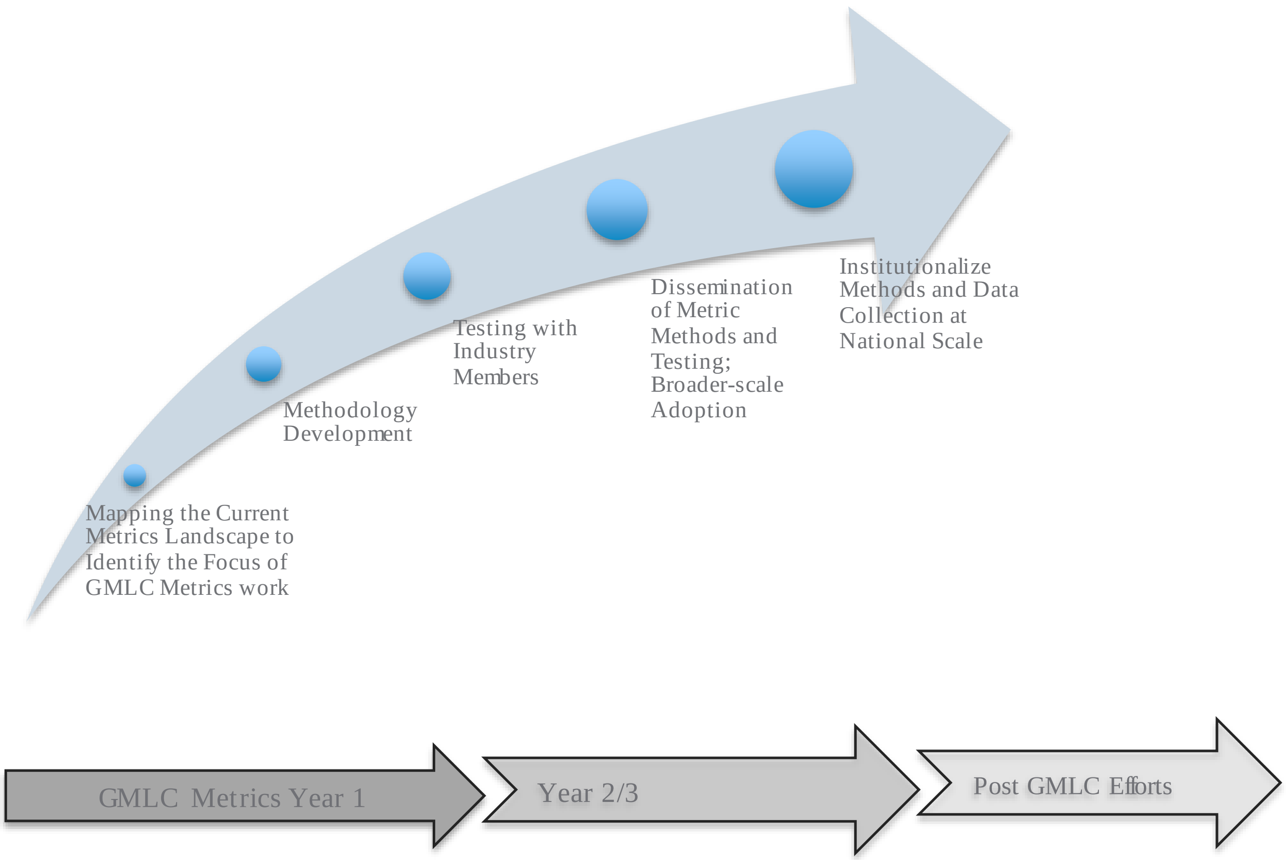

Figure 2.1. Time Line for GMLC1.1 Activities

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 publically 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.

2.1 Stakeholder Engagement

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 are sought out from stakeholders.

Key national organizations in the electric industry were identified as Working Partners at the inception of the project and engaged to provide both strategic and technical input to the project as a whole. 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, but not limited to, the beginning and scoping stages of the effort and then to more formally review the content in this document at the end of Year 1.

The project team engaged with, received feedback from, and in some cases, formed a partnership with the following entities:

Reliability: North American Electric Reliability Corporation (NERC), Institute of Electrical and Electronics Engineers (IEEE), American Public Power Association (APPA),

Resilience: DOE/Office of Energy Policy and Systems Analysis (DOE/EPSA), U.S. Department of Homeland Security (DHS), City of New Orleans, PJM Interconnection, Electric Power Research Institute (EPRI)

Flexibility: Federal Energy Regulatory Commission (FERC), Pacific Gas and Electric Company (PG&E), California Independent System Operator (CAISO), EPRI, Electric Reliability Council of Texas, Inc. (ERCOT)

Sustainability: U.S. Environmental Protection Agency (EPA), Energy Information Administration (EIA), Arizona State University National Resources Research Institute (NRRI), Sustainability Accounting Standards Board (SASB)

Affordability: EPRI, Minnesota Public Utilities Commission (PUC), Colorado State Energy Office, Washington State Utilities and Transportation Commission (UTC), Nation Association of Regulatory Utility Commissioners (NARUC), Alaska Energy Authority

Security: DHS, EPRI, National Association of State Energy Officials (NASEO), Edison Electric Institute (EEI), Exelon Corporation.

In Years 2 and 3, metric category teams will be working with some of the stakeholders listed above, as well as additional ones, to test out the metric methodologies and demonstrate that they are technically feasible and provide value in a real world setting. Working Partners and data organizations will also be engaged at various stages in the upcoming years.

2.2 Integration and Consideration of Multiple Metric Categories

Although each metric category team has drawn a boundary around its particular topic area in order to explore and develop an enhanced set of metrics, there is recognition that there are interactions among the resulting metrics across the categories and that decision makers may consider multiple metric categories when making decisions. To that end, this project also includes a synthesis component, as well as a interactions to the GMLC Valuation Framework Development project (GMLC 1.2.4) that focuses on the development of a grid services valuation framework. Only conceptual work on the synthesis has been completed in Year 1. The majority of this activity is planned in Years 2 and 3.

3.0 Reliability

3.1 Definition

Reliability refers to maintaining the delivery of electric power to customers in the face of routine uncertainty in operating conditions. For utility distribution systems, measuring reliability focuses on interruption in 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.

3.2 Considerations for Metrics Development

The reliability of the electric power system has long been a focus of analysis. Many highly mature metrics are in widespread use for this area. The purposes they serve remain important today. However, there are also rapidly growing needs for new, complementary reliability metrics.

First, household, firm/industrial, and society's dependence on electricity have grown and their expectations for reliability have increased. Hence, it is now important to take explicit account of the value of reliability to electricity consumers in making reliability investment decisions.

Second, restructuring of the electricity industry has led to both federal and state regulatory regimes for overseeing reliability. Hence, it is essential to assess the reliability of the distribution system separately from that of the bulk power system.

Third, uncertainty around the future generation mix and composition of loads has grown. Hence, it is important to improve the treatment of the sources of these uncertainties in reliability planning and operational decisions.

3.3 Existing Metrics and Their Maturity

Lagging metrics measure what has happened, such as how long or how often electric service has been interrupted. They include the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI), both of which are widely used by distribution utilities. [1,2]

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[1] SAIDI measures the total number of minutes each customer, on average, is without electric service for a given time period. It is defined as follows:

$$\text{SAIDI} = \frac{\sum \text{Customer Interruption Durations}}{\sum \text{Total Number of Customers Served}} \tag{1}$$

Higher values of SAIDI correspond to more minutes of interruption experienced by all customers, on average, and therefore indicate that the reliability of the utility is lower than the reliability of a utility with lower values of SAIDI.

SAIFI measures the number of times each customer, on average, experiences a power interruption. It is defined as follows:

$$\text{SAIFI} = \frac{\sum \text{Total Number of Interruptions}}{\sum \text{Total Number of Customers Served}} \tag{2}$$

They also include reporting on individual large events, such as those that are reported to the North American Electric Reliability Corporation (NERC) in accordance with Standard EOP-004 and to DOE using form OE-417.[3] Lagging metrics also include metrics specifically related to the restoration of electric service after power interruptions occur, such as the number of customers restored over time. These metrics are used by both transmission and distribution utilities.

Lagging metrics can be either *ultimate* or *intermediate* measures of events or conditions that have occurred. An ultimate lagging measure of reliability is whether or not delivery of electric power to electricity users has been interrupted. An intermediate lagging metric is an observation of a condition or state of the system that may be a prelude to, or is otherwise associated with, the reliable provision of electricity to consumers. For example, NERC routinely measures the frequency control (e.g., Control Performance Standard 1, Balancing Authority ACE[4] Limit) and frequency response performance of balancing authorities (e.g., Balancing Authority Frequency Response).

Lagging metrics can be applied to both the electric system as a whole or to elements (or equipment) within the electric system. All of the above examples are of lagging metrics applied to the electric power system as a whole. Examples of lagging ultimate metrics for equipment are equipment outages and equipment mis-operation. An example of a lagging intermediate metric for equipment is a measurement of its performance during operation (such as an uninstructed deviation in generator output).

Leading metrics measure aspects of the state of the power system prior to the events that stress it and possibly cause a power interruption. They are used to help assess how well the power system is prepared for these events. For the bulk power system, NERC further divides these metrics into those associated with resource adequacy (e.g., reserve margin—both planning and operating) and operational security (e.g., N-1 planning).

See Table 3.1 for the taxonomy of the above metric types, additional examples, a review of sources of information, and a description of concerns regarding existing metrics, including an indication of which concerns are the planned focus of this GMLC activity.

3.4 Emerging and Future Metrics

Improvements in reliability metric designs are needed to better link metrics to the value of reliability; e.g., the economic costs borne by customers (and utilities) when power is interrupted. Examining these costs involves analyzing information on individual interruptions that is more granular than the information summarized in traditional metrics for annual reliability performance. That is, information is needed on which customers have lost power and for how long. The utilization of this kind of information is essential

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Analogous to SAIDI, a higher value of SAIFI corresponds to more interruptions experienced by all customers, on average, and therefore indicates that the reliability of the utility is lower than the reliability of a utility with lower values of SAIFI.

[2] Starting in 2014, the Energy Information Administration (EIA) began collecting and publishing these data from all utilities in the United States. EIA, furthermore, collects these data in a manner that allows for a rough separation between events originating from the transmission system and events originating from within (and limited to) the distribution system.

[3] Reporting to NERC and DOE on energy emergencies (via EOP-004 and OE form 417, respectively) is mandatory within specific time windows after an event (e.g., 24 hours). These data are intended only to provide immediate, rough situational awareness for first responders; they are not intended to be an archival source of detailed information about what has taken place.

[4] Area Control Error

for introducing economic considerations into grid modernization decisions, so that decision-makers can determine how much improving reliability is worth to a utility, its customers, and society at large. In addition, research into new metrics is needed. For example, transmission metrics for the overall *health* (from a reliability standpoint) of the three U.S. Interconnections each taken as a whole, have only recently been formulated by NERC's Performance Analysis Subcommittee. Research is needed to help make them even more useful in guiding public and private decision-making.

Table 3.1. Taxonomy of lagging and leading metric types.

Type	Source	Example	Metrics	Granularity/Data Sources; Availability	Concerns (bold = focus of GMLC Reliability Task)
Lagging (measured)	System	Ultimate: Customer power interruptions	Annual SAIDI, SAIFI, MAIFI	Distribution utilities; EIA (SAIDI and SAIFI, only)	**Annual metrics of performance must be supplemented by analysis of how individual interruption events affect customers by type and duration in order to assess evaluation of economic impacts on customers.** Annual utility-level metrics do not account for customer-owned standby generation or UPS systems
		Intermediate: Operational performance in compliance with NERC standards	Monthly CPS1 and BAAL scores; Daily IROL and SOL violations; Event frequency response	Balancing Authorities; NERC does not publish routinely	Support only existing standards; do not address distribution systems
		Intermediate/Ultimate: Bulk Electric System performance	Annual SRI	NERC Performance Analysis Subcommittee; NERC Annual State of Reliability	**Ad hoc; not systems-based (see below)**
	Equipment	Ultimate: Equipment outages, mis-operations	Annual outage/mis-operation rates; total outage duration (generators)	Generator/Transmission Operators; NERC GADS and TADS aggregated regionally	**Contribution of individual outage events to overall health of bulk power system cannot be determined**
		Intermediate: Generator uninstructed deviation	Monthly megawatt-hours	Generator Operators; Not published routinely	Data not generally available
Leading (calculated)	System	Operational reliability ("N-1" security; resource adequacy)	None, per se (Real-time/ Day-ahead/Seasonal compliance is mandatory)	Balancing Authorities, Transmission Operators; No reporting requirements	**Binary formulation does not allow for incorporation of uncertainty or provide a basis for discussing robustness**
		Planning reliability	1 day in 10 years LOLE; % reserve margin	Distribution utilities; Integrated Resource Plans	Technical issues associated with how to address load forecast (and generation) uncertainty; how to reflect capacity of renewable/DR; how to treat transmission
		Planning reliability	% reserve margin	Planning Authorities; NERC Reliability Assessments	
	Equipment	Maintenance records	None, per se	Generator/Transmission Operators; No reporting requirements	Data not generally available

3.4.1 Improving Distribution System Metrics

Existing, lagging metrics of distribution reliability (e.g., SAIDI and SAIFI) represent aggregations of interruptions averaged over all customers within a service territory. Consequently, they suppress information that is of growing importance for supporting improvements in the planning and operation of distribution systems. This information, which utilities already collect, involves assessing which *types* customers' have experienced a power interruption and for how long in order to understand the economic costs that power interruptions impose on them. This task is being conducted in partnership with the American Public Power Association. It will develop new metrics that enable direct consideration of the cost of power interruptions to customers that will support future distribution system planning and operating decisions.

A simple example will illustrate the shortcomings of SAIDI and SAIFI, as presently defined. In order to address spatial and customer class information, one can readily envision developing separate SAIDI and SAIFI values that are simply indexed by customer class (e.g., a separate SAIDI and SAIFI for the residential and non-residential classes) and location (e.g., a separate SAIDI and SAIFI for the urban and rural regions within a service territory). Such an approach, however, would still not provide information on the actual durations and numbers of interruptions experienced by customers because SAIDI and SAIFI are averages calculated over an entire population (See Footnote 1). Yet, information on the actual duration and number of interruptions is essential for understanding the economic impacts of these interruptions on customers. To capture information on the number and duration of interruptions actually experienced by customers requires further de-aggregating or un-packing averages and expressing the information, instead, as mathematical distributions. Such distributions would express how many customers (of a given class and location) were interrupted and for how long.

Greater spatial and temporal resolution of information on distribution reliability is already collected, as most utilities have automated outage management systems (OMS) that record the start time, duration, and restoration of power to customers affected by power interruptions (Advanced meter infrastructure (AMI) can in principle measure interruptions for each customer). However, utilities rarely use this information in conjunction with information on the cost of power interruptions to customers. Engagement with industry stakeholders, professional societies (e.g., Institute of Electrical and Electronics Engineers [IEEE]), regulators (e.g., National Association of Regulatory Utility Commissioners [NARUC]), and federal agencies (e.g., Energy Information Administration [EIA]) is needed to better understand the importance of taking these economic considerations into account when making decisions to maintain or improve reliability.

This task will foster these engagements by developing and demonstrating new metrics that capture these, currently under-analyzed, economic aspects power interruptions. The development of new metrics will be supported by linking the Interruption Cost Estimate Calculator developed and maintained by Lawrence Berkeley National Laboratory (LBNL) to more granular information on power interruption. The development of these metrics will be co-sponsored by and demonstrated using information on power interruptions that is being collected by the American Public Power Association.

3.4.2 Improving Transmission System Metrics

Parallel activities will seek, on the one hand, to support industry-led development of new transmission system metrics and, on the other hand, to demonstrate the value of probabilistic approaches for transmission planning.

This first activity will involve working directly with NERC staff to review and develop new ways for presenting information the reliability of the bulk power system. This activity will seek to enhance information, which resides in what are known as the Transmission Availability Data System (TADS) and the Generation Availability Data System (GADS), has been collected by NERC for many years. It includes information reported by transmission and generation owners about the status of transmission system elements and generation units, respectively, including the types and causes of outages over the course of the year.

However, the information reported is about the status of individual transmission system elements or generating unit. It does not contain information about the bulk power system within which these elements and units are located. Consequently, it is not possible from the information currently reported to understand the impact or severity of an outage from the standpoint of overall bulk power system reliability. That is, the information reported, by itself, provides an incomplete context for judging the risks individual outages pose to overall bulk power system reliability. As a result, it is difficult to judge whether overall bulk power system reliability, as a whole, is getting better or worse, based solely on trends in the number and causes of individual transmission element or generation unit outages.

This activity will involve engaging technical experts in the design and operation of the bulk power systems to work with NERC staff to devise means for adding contextual information about the significance of the information NERC already collects on transmission equipment and generating unit outages.

3.4.3 Probabilistic Enhancement of Transmission Planning Metrics

Deterministic criteria and metrics have been used for decades in transmission planning and are currently mandated by NERC. Over the years, a spectrum of planning tools has been developed and used to calculate the deterministic metrics required to implement this planning approach. Although this planning approach fits well into the current framework of transmission decision-making processes as practiced by almost all utilities and regulators, it is difficult to accommodate new sources of uncertainty into them, such as the less predictable patterns of generation from renewables.

One of the most important of these transmission planning techniques, called contingency analysis, which assesses the individual impacts of a large number of contingencies on the system with respect to element capacity ratings, such as under- or over-voltage, and loss of load. The evaluation is binary: a reliability criterion is or is not exceeded. This form of analysis does not take into account the relative frequencies of the individual contingencies. Nor does the pass/fail nature of the evaluation take into account the relative severity of the potential impacts with respect to one another. Yet, understanding the frequency and severity of various contingencies is essential for assessing the risks that contingencies pose to the system and hence the priorities to assign to potential remedies. Note that contingency analysis evaluates system security, i.e., the system responses under disturbances by taking preventive and corrective actions while loss of load probability or expectation (LOLP or LOLE) is used to measure generation adequacy and usually probabilistic by considering the load profile and scheduled and random generation unit outages.

This task intends to enhance the existing deterministic transmission planning metrics such as loss of load and voltage violation with probabilistic metrics, i.e., by associating each of the metrics with a probabilistic distribution determined by the distributions of frequencies and durations of the individual contingencies. The major activities in this task will include the identification of the existence and availability of data sources needed for calculating the probabilistic metrics, the availability of the tools that can be used for the calculation, and more importantly, the demonstration of additional information provided by probabilistic metrics and how transmission planners can make use of such information to help with the decision-making process. In addition, a study of the comparative strength and weakness of both deterministic and probabilistic metrics needs to be performed to demonstrate the usefulness of these metrics.

The purpose of these assessments is to help demonstrate the usefulness of probabilistic planning approaches to transmission planners and thereby help pave the way toward formal adoption of these approaches to complement existing approaches. Many transmission planners are already very interested in moving toward incorporation of such probabilistic planning approaches. The candidates include but are not limited to the Electric Reliability Council of Texas, Inc. (ERCOT), New England Independent System Operator (ISO-NE), and Southwest Power Pool (SPP).

Note that transmission planning authorities will be using both deterministic and probabilistic reliability metrics simultaneously but in a complementary manner—taking advantage of the strengths of both types of metrics. Also note that the focus of this study is on transmission planning. Such a method and tool can be extended to application of operational planning but is beyond the scope of this study.

3.5 Scope of Applicability

This subsection describes the applicability of the three reliability metrics focus areas (distribution system, bulk power system, and probabilistic transmission planning) for different organizational or jurisdictional levels within the electricity industry.

3.5.1 Asset, Distribution, Bulk Power Level

Improved distribution system metrics will apply to utility distribution systems, as a whole, as well as to sub-regions or even individual feeders within a utility service territory. Improved bulk power system metrics will apply primarily to each of the three U.S. interconnected bulk power systems (WECC, ERCOT, Eastern). Probabilistic transmission planning metrics will apply primarily to the footprint of a single transmission planning entity, either that of a utility or a regional planning entity.

3.5.2 Utility Level

Improved distribution system metrics are intended to apply primarily to individual utilities. Improved bulk power system metrics, in contrast, are intended to apply only to entire interconnections. Probabilistic transmission planning metrics are intended to apply primarily to transmission-owning utilities, but can also apply to regional transmission planning entities.

3.5.3 State Level

Improved distribution system metrics for individual firms within a state can be rolled up to the state level. Improved bulk power system metrics are not intended to apply at a state level, with the limited exception of ERCOT, which operates a stand-alone interconnection for the majority of the state of Texas. Probabilistic transmission planning metrics would only apply at the state level when the footprint of transmission planner coincides with state borders (e.g., NYISO and ERCOT).

3.5.4 Regional Level

Improved distribution system metrics for individual firms can be rolled up to the regional level. Improved bulk power system metrics would not normally be measured at a regional level; see discussion above under state level. Probabilistic transmission planning metrics would generally be applicable at the regional level. Again, see discussion above under state level; regional transmission planning entities in the U.S. generally span multiple states.

3.5.5 National Level

Improved distribution system metrics for individual utilities can be rolled up to a national level. Improved bulk power system metrics are intended for entire interconnections of which there are three in the U.S., and of which two include portions of Canada and/or Mexico. Thus, a roll up to a national level may not be meaningful. It is feasible to apply probabilistic transmission planning approaches to a region comprised of multiple utilities or perhaps to an entire interconnection, but they would not normally be applied to the nation, as whole (unless one sought to study interconnecting the three US interconnections and, at the same time, disconnecting them from Canada and Mexico).

3.5.6 Other Level

Not applicable.

3.6 Use-Cases for Metrics

This subsection summarizes the industry partners that we will work with for each of the three reliability metrics focus areas.

With respect to improving distribution system reliability metrics, we will co-develop and demonstrate with the American Public Power Association a new distribution-level metric that captures the economic impact of power interruptions on public utility customers.

With respect to improving transmission system metrics, we will co-develop/demonstrate with NERC a new bulk power system metric to augment (and possibly eventually replace) SRI metric that is reported annually by NERC in the State of Reliability report.

With respect to probabilistic transmission planning metrics, we will work with ERCOT and Idaho Power to compare and demonstrate the strength and weakness of both deterministic and probabilistic reliability metrics and how the two types of metrics can be used to complement each other in transmission planning. ERCOT already provided one year of historical 5-minute-interval generation data of individual wind plants for this purpose. Renewable sources can be modeled as generators in the system. The major difference between conventional generator outages and renewable outages is that different outage modes for renewables have to be considered and modeled, i.e., in addition to a complete loss of generation, under- or over-generation of renewable generators also have to be explicitly modeled. The probabilistic models and the parameterization of the models for such contingencies need to be developed to provide input data to the probabilistic contingency analysis.

3.7 Value of Metrics

Based on engagements with stakeholders, the following specific values were reported:

Improved bulk power system metrics: David Till, Senior Manager for the Performance Analysis Group, NERC reported the following:

- David expressed that the metrics that we currently have are suitable for today's system, but not for tomorrow's. At what point tomorrow comes we can't predict – but we know that will need to have better metrics available before they are needed.
- The overall goal of this collaborative effort is to try to enhance the metrics that are in the report that are led by the Severity Risk Index (SRI). NERC's objective is steady and appropriate integration of new metrics. NERC would like to get to a position where it always has a scale that identifies what needs to be done to increase the reliability of system. This research will determine how this could be done. The aspiration for this project is to develop a much better understanding of SRI – what it can and can't tell us about reliability – and to develop new metrics that will complement SRI that will address things that SRI can't tell us.
- This work effort is likely the start of a long-term collaborative, ground-up exploratory engagement with NERC. The approach being taken in GMLC1.1 is very different from earlier approaches by LBNL. Previously, LBNL has developed a new tool or a new technique and now we are seeking to apply it to NERC's data and use it to calculate value of metrics that we have already developed and demonstrate their usefulness. This project is a much earlier state of interaction in which we are working very collaboratively with the NERC Performance Analysis team to look at data in new ways.

Improved distribution system metrics: Alex Hoffman, Director, Energy and Environmental Services, APPA reported the following:

- APPA has had a long-time interest in maintaining reliable electric systems, and in reliability metrics, specifically on the distribution side of the meter: understanding what they mean and how they can be used by its members to improve and manage reliability. APPA has determined that it can be very helpful to its members to have data and tools that can be used to estimate what their customers lose when a service interruption occurs and to inform potential investments to improve system resilience and reduce some amount of outage. APPA has also found that quantifiable research-based estimates of costs related to outages can be extremely meaningful in the public discourse associated with a utility's investments.
- APPA recently received a DOE grant to expand its efforts to build out a reliability data collection and analysis platform. An intent of the platform, which will incorporate the Interruption Cost Estimate (ICE) Calculator originally funded by DOE and Lawrence Berkeley National Laboratory, is to provide an interface that enables the combination of actual outage data collected by utilities with the publically-funded research on outage cost estimation to generate estimates in a form where they can be used readily by the people who most need them. One output from the platform will be a ranking of a utility's circuits based on outage cost. The platform is expected to be released by September 2017.
- Our APPA partner sees that his collaboration with DOE over the last half decade is now in a position to legitimately evaluate the efficacy of existing distribution system metrics and to invent new metrics that address any gaps. Based on data provided by utility application of the reliability data collection and analysis platform, APPA and the project team will jointly develop new metrics and assess if they have value through a trial and error approach, based on developing an understanding of how utilities are using the outage cost information, how that cost is experienced across utilities, and how the information stands up to public discourse, and then working back to identify measures that improve the understanding of cost.
- The outcomes of this effort are expected to be useful to investor-owned and other utilities beyond APPA's members, as there are no fundamental differences in the types of customers served by these

utilities or the types of damages those customers might experience from an outage that would require distinct definitions of the value of reliability.

Probabilistic transmission planning metrics:

The review meeting with the stakeholders for the principal use case that will be explored for this metric had not taken place at the time of this update to the reference document. This information will be added in a future update to this document.

3.8 Links to Other Metrics

There are important linkages to resilience and flexibility/adaptability metrics. For example, metrics for restoration times and emergency preparedness are also considered in resilience metrics. Similarly, reserve margin, especially operating reserve margin, is also considered among metrics for flexibility/adaptability.

4.0 Resilience

Historically, U.S. government policy toward critical infrastructure security has focused on physical protection. However, after the terrorist attacks of September 11, 2001, the devastation from Hurricane Katrina in 2005, and a series of other disasters in the early 2000s, the infrastructure security community in the United States and around the world recognized that it was simply not possible to prevent all threats to all assets at all times. Consequently, assuring critical infrastructure resilience emerged in the United States and across the globe as a complementary goal to prevention-focused activities. Whereas critical infrastructure security policies historically emphasized prevention of terrorism, accidents, and other disruptions, critical infrastructure resilience activities emphasize the infrastructure's ability to continue providing goods and services even in the event of disruptions. Together, critical infrastructure security and resilience strategies provide a more comprehensive set of activities for ensuring that critical infrastructure systems are prepared to operate in an uncertain, multi-hazard environment.

Today, resilience is at the forefront of several efforts by local, state, and federal governments and agencies. However, no consensus exists at present about how to define or quantify resilience. This issue was highlighted in the National Academy of Sciences' report on disaster resilience: "without some numerical basis for assessing resilience, it would be impossible to monitor changes or show that community resilience has improved. At present, no consistent basis for such measurement exists…" (NRC 2012). To date, resilience definition and metric development are very active areas of research.

Historically, reliability metrics represent the standards by which delivery of electric power by utilities was evaluated. In the grid community, resilience has only recently emerged as a concept that is starting to be prioritized, but an opportunity exists to leverage previous work from other infrastructure areas to the grid.

4.1 Definition

As noted above, no resilience definitions or metrics have been universally accepted by the grid community. Still, a rich discussion and body of research on these topics is currently ongoing, and GMLC1.1 leverages that information to inform its recommendations on grid resilience metrics.

Presidential Policy Directive 21 [PPD-21] (Obama 2013) asserts the following definition of resilience:

> The term 'resilience' means the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents.

PPD-21 establishes a national policy on critical infrastructure resilience; additionally, PPD-21's resilience definition is consistent with most other proposed definitions (e.g., Biringer et al. 2013). Consequently, this project uses this definition for establishing grid resilience metrics.

4.2 Existing Metrics and Their Maturity

Even though universally accepted grid resilience metrics do not currently exist, a number of leading organizations within the community have asserted needs and requirements for resilience metrics and analysis methodologies. For example, the NARUC has asserted that current reliability metrics are not sufficient for informing analyses on investments for large-scale disruptions (such as hurricanes, earthquakes, etc.) and that resilience metrics need to be designed to meet that gap (NARUC 2016). The

Electrical Power Research Institute (EPRI) is researching the development of risk-based metrics, methods for quantifying resilience, and methods for selecting among various options for reducing the risk of damage to the bulk power and distribution systems during severe events (EPRI 2015a). The Edison Electric Institute (EEI) notes that no single solution exists to make all systems more resilient; rather, "utilities and their regulators must look at the full menu of options and decide the most cost-effective measures to strengthening the grid" (EEI 2014). PJM is actively developing tools to analyze the resilience of the grid to cascading failures. DOE has also explored energy resilience analysis frameworks in the Quadrennial Energy Review and Quadrennial Technical Review (Watson et al. 2015; DOE 2015b, c).

GMLC1.1 also identified two main categories of metrics that have been proposed for quantifying resilience in the grid and other infrastructure. They are as follows:

- Attribute-based: Attribute-based metrics generally try to answer the question "What makes my system more/less resilient?" and can be used to provide a baseline understanding of the system's current resilience, relative to other systems. Thus, they typically include categories of system properties that are generally accepted as being beneficial to resilience. Examples of these categories might include robustness, resourcefulness, adaptivity, recoverability, etc. Application of these metrics typically requires that analysts follow a process to review their system and determine the degree to which the properties are present within the system. These determinations are usually made by collecting survey responses, developing a set of subjective weighting values that represent the relative importance of the survey responses, and performing a series of calculations that result in numerical scores for the resilience attributes.
- Performance-based: Performance-based metrics are generally quantitative approaches for answering the question "How resilient is my system?" These methods are used to interpret quantitative data that describe infrastructure outputs in the event of specified disruptions and formulate metrics of infrastructure resilience. The required data can be gathered from historical events, subject matter estimates, or computational infrastructure models. Because the metrics can often be used to measure the potential benefits and costs associated with proposed resilience enhancements and investments, performance-based methods are often ideal for cost-benefit and planning analyses.

4.2.1 Requirements

To establish a set of needs and requirements for grid resilience metrics, GMLC1.1 engaged with stakeholders from the grid community and reviewed the current literature on this topic. The project identified the following as commonly asked resilience questions:

- How do I measure the resilience of my system?
- If that a disruptive event is imminent (i.e., will occur within hours to days), what can I do to mitigate the consequences of such an event and increase the resilience of my system?
- How should I plan and invest to make my system more resilient across the spectrum of uncertain, future events?

Stakeholders further noted the following considerations for resilience metrics:

- Context. Grid resilience metrics should be specified in the context of low-probability, high-consequence potential disruptions. This context will help distinguish them from reliability metrics.
- Performance-based metrics. Grid resilience metrics should be based on the performance of power systems, as opposed to relying solely on the attributes of power systems. Use of performance-based metrics will maximize the utility of grid resilience metrics for baseline assessments, response and recovery activities, and planning and investment efforts.

- Consequences. Grid resilience metrics should quantify the consequences that occur as a result of strain on or disruption of the power grid. These consequences can be closely related to grid operations and power delivery (e.g., megawatt-hours of power not delivered as a result of a storm, utility revenue lost, cost of recovery to the utility, etc.) and hence have some similarities to existing reliability metrics. Or they can be measured in terms of greater community impacts such as populations without power (e.g., measured in people-hours), business interruption costs resulting from the power outage, impacts on critical infrastructure functionality, loss of Gross Regional Product, etc.
- Prioritization. Resilience metrics should be useful for prioritizing which hazards should be planned for and which investments and response actions should be taken to improve resilience to these hazards. This ability would not only help grid operators decide which actions are beneficial, but it could also prove useful for supporting rate-cases and grant applications.
- Forward-looking. Much of the current focus on resilience analyses is planning for the future, and less emphasis is being placed on benchmarking. Hence, resilience metrics should be "forward-looking" and characterize the power system's ability to cope with hazards that could potentially happen in the future.
- Modeling and simulation. Given that many resilience analyses focus on low frequency events such as geomagnetic disturbances or electromagnetic pulses, sufficient historical data may not be available to characterize grid resilience for all hazards of interest. Hence, grid resilience metrics should have sufficient flexibility to use data from modeling and simulation activities that explore postulated hazards and scenarios, if needed. Though the current state of modeling and simulation tools may be limited or of research grade for certain hazards, grid resilience metrics need to be designed with sufficient flexibility to include data for these tools when they are ready.
- Consistency. A current challenge for resilience analyses is the lack of standard grid resilience metrics and analysis methods. Stakeholders have identified a need for standardized consistent metrics that can enable hazard prioritization, mitigation, and investment comparisons, etc.
- Uncertainty. To the extent possible, grid resilience metrics should be reflective of the inherent uncertainties that drive response and planning activities. These uncertainties include disruption conditions (e.g., frequency of events, track of the hurricane, wind speeds), damage to the grid, demand from affected population, time required for response, and other factors.
- Emerging and future metrics.

With the above considerations in mind, the project has developed a set of grid resilience metrics and a process for calculating them. The metrics and process have been developed to accomplish the following:

- Help utilities better plan for and respond to low-probability, high-consequence disruptive events that are not currently addressed in reliability metrics and analyses.
- Provide an effective, precise, and consistent means for utilities and regulators to communicate about resilience issues.
- Provide an effective, precise, and consistent means for utilities and the communities that they serve to communicate about resilience issues.

GMLC1.1 recommends that grid resilience metrics be consequence-based and, to the extent possible, reflective of the inherent uncertainties that drive response and planning activities. These uncertainties include disruption conditions (e.g., frequency of events, track of the hurricane, wind speeds), damage to the grid, demand from affected population, time required for response, and other factors, so consequence estimates may take the form of probability distributions.

Table 4.1 includes a list of example consequence categories that could serve as the basis for resilience metrics. All of the consequence categories are measured for the defined system specifications and therefore may be measured across spatial (geographical) and temporal (duration) dimensions.

Table 4.1. Examples of consequence categories for consideration in grid resilience metric development.

Consequence Category	Resilience Metric
Direct	
Electrical Service	Cumulative customer-hours of outages Cumulative customer energy demand not served Average number (or percentage) of customers experiencing an outage during a specified time period
Critical Electrical Service	Cumulative critical customer-hours of outages Critical customer energy demand not served Average number (or percentage) of critical loads that experience an outage
Restoration	Time to recovery Cost of recovery
Monetary	Loss of utility revenue Cost of grid damages (e.g., repair or replace lines, transformers) Cost of recovery Avoided outage cost
Indirect	
Community Function	Critical services without power (e.g., hospitals, fire stations, police stations) Critical services without power for more than N hours (e.g., N > hours of backup fuel requirement)
Monetary	Loss of assets and perishables Business interruption costs Impact on Gross Municipal Product or Gross Regional Product
Other critical assets	Key production facilities without power Key military facilities without power

To include uncertainties, resilience metrics need to include a measure of consequences and the relevant statistical property from the probability distribution of those consequences. Table 4.2 lists examples of relevant statistical properties and these properties should be combined with consequences categories to define resilience metrics. For example, mean time to recovery and probability that utility revenue losses will exceed $100 M are two examples of how consequence (time to recovery and utility revenue losses) and statistical properties (mean value and probability of exceedance) can be combined.

Table 4.2. Examples of statistical properties that can represent uncertainty.

Statistical Property	Description
Expected value (mean)	The probability weighted average
Quantiles (Confidence Intervals)	Quantiles divide the range of a probability distribution into contiguous intervals with equal probabilities, and the confidence interval is the specified probability that any predicted value lies within a given quantile.
Value at Risk (VaR)	A measure of the risk for a chosen probability. For example, a 5% VaR of 1,000 means that there is a 5% probability that the distribution exceeds 1,000 units. 5% is a commonly selected probability for VaR.

Table 4.2. (contd)

Statistical Property	Description
Conditional Value at Risk (CVaR)	Another measure of risk. Assuming a loss occurs (conditional), it estimates the expected value for the worst *X* percentage of cases. That is, CVaR takes into account the shape of the tail of a distribution. For example, a 5% CVaR of 5,000 means that the expected value of the largest 5% of the distribution is 5,000.
Maximum/Minimum (worst case)	The largest/smallest predicted value; depending on the metric, it defines one of these extremes as the worst case.
Other	In some cases, functions that combine several statistical properties are employed. For instance, a linear combination of the mean and the CVaR accounts for a risk-averse approach that also takes into account average outcomes.

Though the focus is to identify metrics for quantifying grid resilience, it is just as important to describe the process for calculating those metrics. We recommend an extension of the Resilience Analysis Process (RAP), originally developed by Watson et al. (2015) for the 2015 Quadrennial Energy Review (QER), be used to develop and apply grid resilience metrics. The RAP (Figure 4.1) is a seven-step process that can be used to help specify resilience objectives for utilities, select the appropriate metrics that are reflective of those objectives, gather the necessary data to populate the metrics, and ultimately decide on the best path forward for making resilience-based decisions. The seven steps are as follows:

1. **Define resilience goals.** The first step in the process is specifying the resilience goals of the analysis. The goals lay the foundation for all following steps. For example, the specific goal could be to assess the resilience of a power system to a previous historical event. Alternatively, the goal could be to evaluate possible system improvements. In some instances, multiple goals may exist, such as assessing a historical event and evaluating options if the system was deemed not to be sufficiently resilient to the historical event. If evaluating improvements is within the scope of the analysis, a decision should be made about the kinds of changes to be considered and the types of questions the analysis should address. System specification (e.g., geographic boundaries, physical and operational components, relevant time periods, etc.) is also required. Additionally, in this stage key stakeholders and any possible conflicting goals should be identified.
2. **Define consequence categories and resilience metrics.** In the context a specified hazard, the RAP measures the resilience of a power system by quantifying the consequences of the hazard to the power system and other infrastructures and communities that depend upon the power system. The second step in the RAP is to select the appropriate consequence categories, which should reflect the resilience goals. In some instances, the consequence estimates and resilience metrics may focus on the impacts directly realized by the utility, such as power not delivered, loss of revenue, cost of recovery, etc. However, in other instances, direct impacts are only part of the resilience assessment. Energy systems provide energy not just for the sake of generating or distributing it, but for some larger community benefit (e.g., transportation, healthcare, manufacturing, economic gain). Resilience analyses that aim to include a broader community perspective may convert power disruption estimates into community consequence estimates (e.g., number of emergency service assets affected, business interruption costs, impact on gross regional product, etc.). Table 4.1 includes a list of example consequence categories that could serve as the basis for resilience metrics. Data availability may also affect selection of consequence categories. Resilience analyses are not restricted to a single consequence category when developing metrics. Rather, the use of multiple consequence categories can be beneficial for representing various stakeholder perspectives.
3. **Characterize hazards.** Hazard characterization involves the specification of hazards of concern (e.g., hurricane, cyber-attack, etc.). Any number of hazards can be specified, but typically, stakeholders will have a limited number of hazards or a prioritized list of concerns. Development of hazard scenarios

includes detailing the specific hazard conditions. For example, if a hurricane is the specified hazard, the hazard scenario could specify the expected hurricane trajectory, wind speeds, regions with storm surge and flooding, landfall location, duration of the event, and other conditions needed to sufficiently characterize the hazard and its potential impact on the power system.

4. **Determine the level of disruption.** The fourth step is determining the level of disruption. This step specifies the level of damage or stress that grid assets are anticipated to suffer under the specified hazard scenarios. For example, anticipated physical damage (or a range of damage outcomes when incorporating uncertainty) to electric grid assets from a hurricane hazard might include substation X is nonfunctional due to being submerged by sea water, lines Y and Z are blown down due to winds, etc. Damage specification should not only indicate which assets are nonfunctional or degraded but how severely the asset is impaired and what recovery steps are needed to repair overall system functionality.

5. **Collect consequence data via system model or other means.** When assessing the resilience of a power system in response to an actual, historical event, data collection can be typically performed by gathering system or community data that describe the magnitude and duration of the disruption to power delivery. Utilities maintain OMSs, which are often a rich source of data for resilience analyses; however, for the largest events, these systems often lack details such as the actual locations of the causes of the individual outages and information about system design and condition. When conducting forward-looking analyses, system-level computer models can provide the necessary power-disruption estimates. These models use the damage estimates from the previous RAP step as inputs to project how delivery of power will be disrupted. For example, anticipated physical damage (or a range of damage outcomes when incorporating uncertainty) to an electric grid from an earthquake can be used as input to a system model that projects how the damage results in load not being served. Multiple system models may be required to capture all of the relevant aspects of the complete system. Furthermore, dependencies may exist between models. For example, a repair and cost model may be used to determine a repair schedule for components of an infrastructure. The schedule determined by these models may inform systems models used to assess how the systems perform during the restoration period.

6. **Calculate consequences and resilience metrics.** When evaluating resilience, direct impacts on system output as a result of damage are only part of the story. Most energy systems provide energy for some larger social purpose (e.g., transportation, healthcare, manufacturing, economic gain). During this step, outputs from system models are converted to the resilience metrics that were defined during Step 2. When uncertainty is included in this process, probability distributions will characterize the resilience metric values.

7. **Evaluate resilience improvements.** Unless this process is being undertaken purely for assessment purposes, it is likely that decisions must be made about how to modify operational decisions or plan investments to improve resilience. After developing a baseline for resilience quantification by completing the preceding steps, it is possible and desirable to populate the metrics for a system configuration that is in some way different from the baseline in order to compare which configuration would provide better resilience. This could be a physical change (e.g., adding a redundant power line); a policy change (e.g., allowing the use of stored gas reserves during a disruption); or a procedural change (e.g., turning on or off equipment in advance of a storm).

Figure 4.1. The resilience analysis process (Watson et al. 2015).

Consider Superstorm Sandy and the impact it had on power delivery when it made landfall on the evening of October 29, 2012. The day after the storm hit, 8.7 million customers experienced power outages; 90 percent of those customers were in Long Island and over 1 million of Con Edison's 3.3 million customers were affected. In some areas, the impacts lasted for months. The following hypothetical application is presented to demonstrate how the RAP can be used in practice.

Consider that a hypothetical utility, Tesla Electric (Tesla), had its operations severely compromised by Superstorm Sandy. Tesla has identified two possible options for enhancing its resilience to future storms (Table 4.3). Option A focuses on hardening 20 substations that were damaged by the storm and resulted in 80 percent of the lost load. Option B focuses on installing AMI upgrades that would facilitate a more rapid restoration but not prevent any actual damage. Both options would also include installation of combined heat and power (CHP) in critical infrastructure assets and enabling photovoltaic (PV) systems to operate in islanded mode.

Table 4.3. Resilience enhancement options.

Option A: $350M	Option B: $250M
• Harden 20 substations that experienced 80% of loads with power outages. • Install CHP for uninterrupted heat and power in 60 critical community assets affected during the storm. • Enable PV systems to operate in islanded mode.	• Install AMI upgrades to enable remote detection and power restoration. • Install CHP for uninterrupted heat and power in 60 critical community assets affected during the storm. • Enable PV systems to operate in islanded mode.

Tesla chooses to evaluate the options by assessing how the options would lessen potential consequences that could occur in the event of future storms. They are interested in consequences to their customers, the community they serve, and themselves. Specifically, Tesla selects three consequence categories (Table 4.4): magnitude of power outages that could occur in the event of a future storm; estimated costs to Tesla for repairing the storm damage and recovering; and the number emergency service assets (e.g., hospitals and police stations) expected to be without power for more than 48 hours. These consequences establish the resilience metrics that Tesla will use to evaluate the two investment options.

Table 4.4. Consequence categories for resilience analysis.

Consequence	Resilience Metric	Units of Measurement	Calculation Process
Outage Magnitude	Cumulative daily power outages	Customer-days without power	$\sum_{t=1}^{10} x(t)$, where $x(t)$ is the number of customers without power on day t, and $t=1$ is the 1st day of the analysis (October 29, 2012), $t=2$ is the 2nd day, etc.
Recovery Costs	Repair and recovery costs bore by the utility	$ (dollars)	$\sum_{t=1}^{10} c_{labor}(t) + c_{materials}(t) + c_{parts}(t)$, where $c_{labor}(t)$ is the cost of labor spent on recovery activities on day t, $c_{materials}(t)$ is the cost of materials spent on day t, and $c_{parts}(t)$ is the cost of parts spent on day t
Community Impact	Emergency service assets without power for more than 48 hours	# of assets	$h + p + f$, where h, p, and f, denotes the number of hospitals, police stations, and fire stations, respectively, in Tesla's service region that lost power for more than 48 hours

Given that no one can predict with complete certainty the precise characteristics of future storms, Tesla selects two storm scenarios for their analysis. The first scenario is a Superstorm Sandy-like event that is a category 1 hurricane with Sandy-level floods ranges. The second scenario is a more severe storm, a category 2 hurricane with more extreme flooding. Based on projections from the research literature, Tesla estimates the probabilities that the category 1 and category 2 storm scenarios occur before 2100 are 33 percent and 17 percent, respectively.

For the two hurricane scenarios, the utility projects the resulting level of damage on each component in the power system. The utility leverages their OMS to characterize the damage inflicted by historical events similar to Sandy for different storm categories. For each critical utility component, the utility is able to assign a conditional probability that the component will be damaged, conditional upon each of the two hazard scenarios and the options that are implemented.

The utility then exercises their power flow model in a Monte Carlo simulation. In each realization, the following parameters are determined stochastically:

1. Category (1 or 2) of the storm: The individual probabilities that a category 1 or category 2 storm will occur are 0.33 and 0.17, respectively. Because the utility wants to know the impact of the options if one of the storms happens in the future, they use the conditional hazard probability. That is, given that a storm will occur, there is a 0.66 probability the storm will be a category 1 hurricane and a 0.34 probability the hurricane is a category 2 hurricane.

2. Damage to a system component: Component damage probabilities are conditional upon the hazard scenario and which option was installed.

For the Monte Carlo simulation, the utility performs 100 realizations for Option A and 100 realizations for Option B. The assessment team collects the simulation outputs for the projected outage estimates, costs of recovery, and impacts on critical assets. They use these data to calculate the expected values for each of the resilience metrics.

Simulation results describing the results of Tesla Electric for each option are shown in Table 4.5. Mean consequences are reported. Additionally, the 10th and 90th percentiles of the distributions are also included to illustrate the variability of the estimates.

Table 4.5. Simulation results for multiple scenarios describing damage uncertainty.

Option	Disruption	Cumulative customer-day outages (millions)	Critical facilities outages	Cost of recovery (M$)
	Mean	1.1	1	319
A	*10^{th} %ile*	0.5	0	189
	90^{th} %ile	1.35	8	330
	Mean	1.3	1	450
B	*10^{th} %ile*	1.05	0	300
	90^{th} %ile	1.46	8	500

The results in Table 4.5confirm that option A, even with its higher investment costs, would likely provide a higher benefit across all resilience metrics. On average, Option A would save $130M in recovery costs (i.e., $450M - $319M = $131M), helping make up for the larger upfront cost of Option A.

The above example is a simplified version of how the RAP and grid resilience metrics could be applied to inform a set of resilience-related decisions. See Vugrin et al. (2017) for a more detailed discussion of the RAP and recommended grid resilience metrics.

4.2.2 Additional Considerations

For the sake of brevity, the hypothetical application described above is intentionally simplified. However, some important considerations should be added to clarify the current state of grid resilience metrics and analysis.

First, it should be noted that the availability of computer modeling and simulation tools that can be used to inform grid resilience analysis and planning is limited. PJM and Sandia National Laboratories are currently piloting computer modeling tools for a limited number of hazards. However, additional R&D is needed to expand the hazards that can be analyzed using similar computer modeling capabilities. In addition to the R&D of these tools, demonstration applications are needed on actual power systems to validate the tools and provide stakeholders with sufficient confidence to trust the results.

Another factor for consideration is that use of probabilistic measures for grid analysis may represent a culture shift for some grid stakeholders. Effectively communicating risk and probabilities is a common challenge, so it should be noted that the use of probabilistic grid resilience metrics may face similar challenges.

Finally, grid resilience decisions are (almost) never made without consideration of more traditional grid measures such as reliability. When evaluating grid resilience enhancement options, grid stakeholders simultaneously consider the potential effects that the options could have on reliability, sustainability, and other measures. In some instances, changes can be beneficial to grid resilience and other measures. In some instances, a change can benefit resilience but have a negative impact on other measures. Ultimately, grid operators and stakeholders evaluate the potential tradeoffs before taking actions.

4.3 Scope of Applicability

4.3.1 Asset, Distribution, and Bulk Power Level

The metrics are reasonably well suited for distribution and bulk power systems. They are generally not applicable to individual assets such as an individual transformer or individual line.

4.3.2 Utility Level

The metrics have been specifically designed for use at the utility level. Pilot studies are currently being conducted at this scale.

4.3.3 State Level

The metrics have not been designed for use at the state level.

4.3.4 Regional Level

The metrics are potentially useful at a community or regional scale; the exact geographic distribution would be determined by the extent of the power distribution system and the communities and infrastructures that are included within the study and dependent upon the power system.

4.3.5 National Level

The metrics have not been applied for use at the national level because of the immense complexity. However, there is no methodological reason to apply the RAP approach to the national level.

4.4 Value of Resilience Metrics

As noted by NARUC, there is a need for grid metrics that can be used to measure and plan for low-probability, high-consequence disruptions to the grid. Reliability metrics were not designed for these situations, so there is a recognized gap. Resilience metrics are intended to address that gap.

The RAP and resilience metrics described above are specifically designed to help utilities plan for and respond to these kinds of events. The RAP's use of consequence-based metrics is well-tailored to cost-benefit decisions that utilities make when making planning and investment decisions. The RAP also provides a uniform, repeatable process for conducting resilience analyses. Its rigor, transparency, and repeatability can help remove some of the ambiguity around resilience and facilitate precise, detailed conversations between utilities and grid stakeholders. Finally, the inclusion of uncertainties with resilience metrics helps provide a more comprehensive understanding of how the grid will perform in the event of a hazard and how much potential mitigations will truly benefit the utilities and dependent communities.

4.5 Links to Other Metrics

There are important linkages to reliability. Resilience focuses on the low-probability, high-consequence disruptions, and reliability is intended for the more frequent, smaller scale interruptions. Given the importance of reliability from a regulatory perspective, it is important to understand any potential (good or bad) impacts on reliability that might come from resilience investments. Flexibility and adaptability, in principle, tend to be attributes of systems that enhance resilience, so there are potential linkages with these metrics as well.

Finally, as noted in PPD-21, security and resilience are considered to be complementary. Whereas security activities tend to consider a system's ability to prevent the hazard from being realized, resilience activities focus on managing consequences when the hazard is realized.

4.6 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 resilience 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 EPRI, the Department of Homeland Security (DHS), and City of New Orleans, Louisiana, and PJM. The following is a synopsis of the key points made during the 1.5 hour briefing:

- Reliability and resilience are closely related. The impact metrics of failed reliability or resilience are an outage measured by its extent (i.e., number of customers or load affected) and by its duration. The difference between reliability and resilience is that the threats or operational hazards are more severe and include off-design conditions such as exposure to hurricanes and flooding.
- It is not clear whether any measure performed to increase resilience will also improve reliability. What has been observed in the aftermath of Hurricane Sandy is that improved resilience increased the flexibility of the grid such that circuits could be sectionalized and switched.
- Collaboration with industry: As part of a GMLC regional partnership project with New Orleans, the local utility company (Entergy) is collaborating with DOE laboratories to work on resilience analyses using the laboratories' approach.
- Value to the community: It is very important from a recovery assistance perspective to have transparent and repeatable methodologies developed that prioritize investment options for improving the resilience of any infrastructure. The approach developed here for the electric grid, will hopefully be employed across all sectors so that we understand better how risk affects the resilience of our communities.
- Implementation of resilience metrics and analysis processes: 1) regulators could require reporting of resilience assessments, and 2) recovery funding from federal sources could require some prior resilience assessment as part of the request for recovery funding.
- The RAP described in this document is not yet standardized in a tool that is available either as an open source product or through commercial vendors. Individual components, such as power flow models exist, but many other analytics are employed to perform a full risk-based hazard/threat assessment and perform modeling to estimate the improved system behavior and operational survivability of grid assets relative to a given threat.

- Regarding retrospective versus prospective views of resilience, several of the participants noted the importance of forward-looking metrics because their organizations tend to pose forward looking analysis questions such as how to prioritize investments to achieve improved resilience.
- The ability to represent uncertainties in metrics is needed, but it is expected to be a challenge. Representing uncertainties provides a more realistic picture of confidence in consequence estimates; however, probabilistic metrics may represent a culture shift and take some getting used to.
- The spatial scope of the analysis may dictate the complexity of the resilience assessment. For instance, assessment of cities or metro areas with highly integrated infrastructure systems may require analysis of interactions of failure. However, resilience analyses for an RTO area may focus on the electric grid because the interactions with other infrastructures are weak or loosely coupled.

5.0 Flexibility

5.1 Definition

Grid flexibility refers to 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. Operational flexibility refers to the ability to respond to relatively short-term operational and economic variabilities and uncertainties that are likely to stress the system or affect costs. Planning flexibility refers to the ability to adapt to variabilities and uncertainties over the long term.

In this document, we focus on flexibility as a property of the bulk-power systems. We recognize that there are flexibility constraints in the distribution system that may limit the amount of renewable energy technology to be deployed. In later versions of this Reference Document, we will address flexibility associated with distribution systems topologies and operations. We also focus on variability and uncertainty that may be caused by high penetrations of variable resource renewable generation in order to meet renewable portfolio standards established by states such as California and Texas.

5.2 Background

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. Traditional reliability measures account for the likelihood of a reliability event due to generation and transmission outages, but do not account for the likelihood of an event due to insufficient flexibility. In the past, maintaining adequate capacity could ensure reliability, but future power systems with larger shares of variable renewables must also have capacity that is sufficiently flexible to accommodate large swings in load net of wind and solar generation. The challenge is illustrated in Figure 5.1, which shows historical and projected net loads at higher levels of renewable penetration in California. As indicated by the data in the figure, solar generation depresses net load in the middle of the day so that large ramp rates in generation from other sources must be provided to meet the evening peak when no solar generation is available. An update of the net load curves with historical data is shown in Figure 5.2, which displays the lowest March daytime net load for the years 2011 through 2016. The projected net load curve for the year 2016 in Figure 5.1 closely matches the historical net load for that year shown in Figure 5.2. A ramp up of 11,000 MW in 3 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.

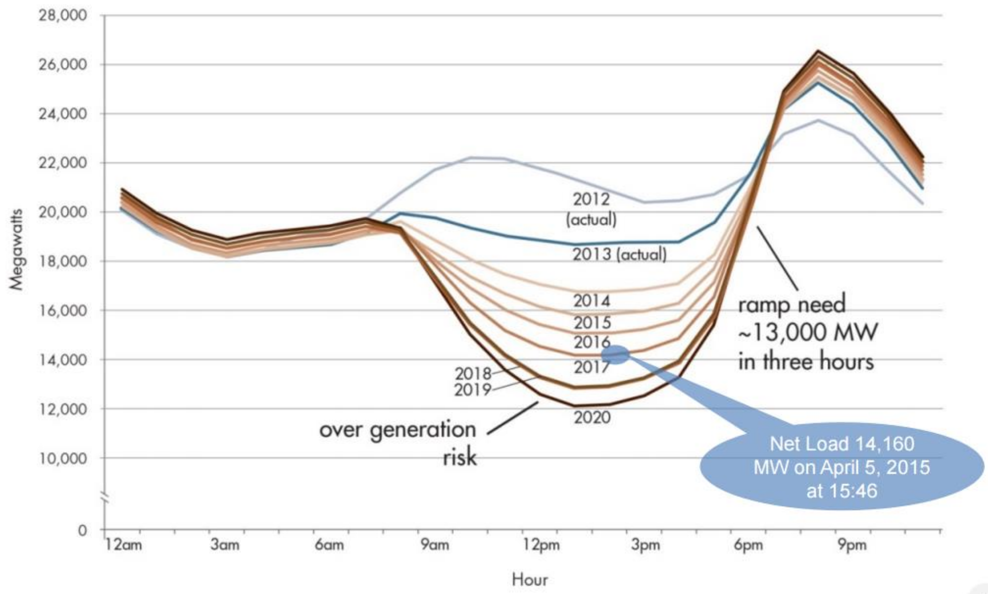

Figure 5.1. Historical and projected net load in California during a typical spring day.[1]

With growth in the share of variable renewables, flexibility is of growing importance and the time is ripe for standardizing measures of flexibility. This project will consolidate information about existing measures of flexibility, provide leadership toward coalescing around primary measures of flexibility, and provide a pathway for moving from research into identification of flexibility metrics to data collection and tracking.

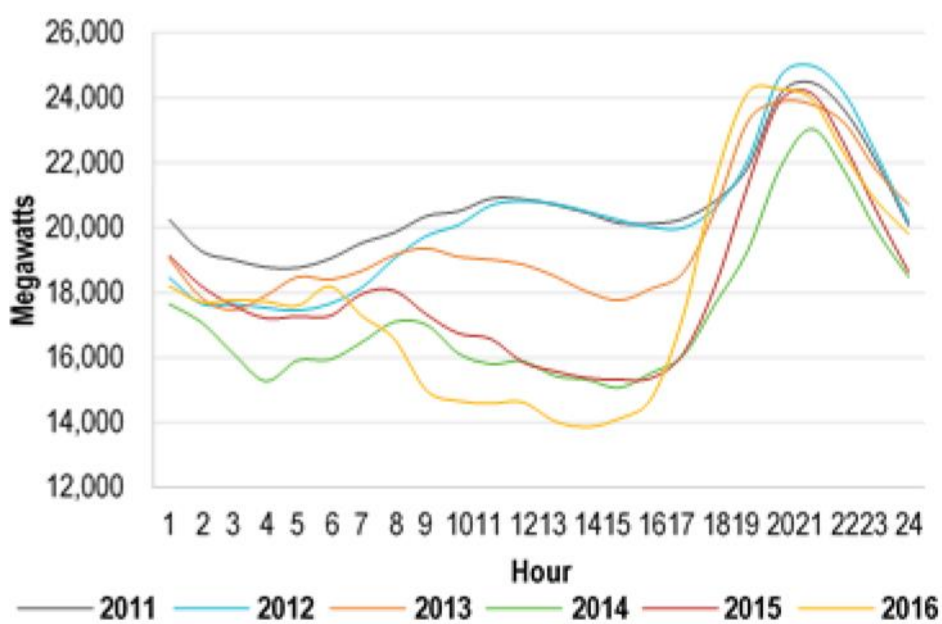

Figure 5.2. Update of the California net load curve with historical data for years 2011–2016.[2]

[1] California Independent System Operator planners have characterized large swings in net load (gross load – renewable generation) under high renewable penetration scenarios. http://www.caiso.com/Documents/Briefing_DuckCurve_CurrentSystemConditions-ISOPresentation-July2015.pdf

5.3 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 a number of 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 (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 (WECC)
  - periods of flexibility deficit (EPRI)
  - insufficient ramping resource expectation (EPRI/academic)
  - flexibility metric (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 [SDG&E])
  - binding flexibility ratio (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 *lagging* metrics that measure what has happened and *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

[2] 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).

Performance Standard 1 [CPS1] scores), renewable curtailment, wholesale price volatility including negative prices, or constrained ramp rates.

Balancing authorities, Independent System Operators (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 or 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 Insufficient Ramping Resource Expectation metric and Periods of Flexibility Deficit to augment the traditional reliability metric of loss-of-load expectation. The SPP 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 is 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 1 day in 10 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 to develop an approach to examine the details of each loss-of-load event realized in the simulation model in order to infer causality.
- Expected unserved energy (EUE) – The expected unserved energy (megawatt-hours) is another reliability metric that could be adapted to measure flexibility deficiencies, similar to 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.

Existing metrics that could be 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. In the second and third years of this project we plan to work with ERCOT and CAISO stakeholders to quantify these relationships.

- Fraction of load under interruptible tariffs – Interruptible tariffs have been used for many years by many 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 (megawatts 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 indicative of over-generation conditions that may be due to flexibility or possibly transmission line outages.

As discussed in Section 5.4, metrics will be used individually and in combination to infer inadequate system flexibility.

5.4 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 long-term planning, in order to identify portfolios of resources, and in real-time operations. 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 identify standard levels of flexibility that need to be met to identify 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 identify 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 comparison of 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 explore 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 be also be analyzed.

During the initial work the team began by working in areas where flexibility has already been highlighted to be of interest. In particular, we reached out to key stakeholders in California (investor-owned utilities, CAISO, California Public Utilities Commission [CPUC]), and in Texas (ERCOT). We 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 and 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 needs to 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 propose that the ratio of the capability to respond to uncertainty to the expected range of uncertainty at any time could be a consistent measure of the flexibility of the system 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 Insufficient Ramping Resource Expectation.

Metrics need to consider the need to evaluate both operational flexibility and the need to incorporate 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 of the generators in the system.

5.4.1 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 (loss-of-load expectation) due to a deficiency in ramping capability over some short time period (<1 hour) as opposed to insufficient availability. A multi-hour metric, LOLE_multihour, is also under development. 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 Insufficient Ramping Resource Expectation (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 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 day, season, and weekday/weekend. This metric could be used to characterize demand for flexibility.
10. Maximum ramp rate in net load – Ramp rate (megawatts 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 (megawatts per minute or percent of total generation) over 5-minute, 1-hour, and 4-hour durations.
12. Energy storage – Total energy storage in megawatts and megawatt-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 megawatt and megawatt-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 megawatt-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 megawatt-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 fraction of the hours in the year prices are negative or the product of negative prices and megawatt-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 the product of excessive positive prices and megawatt-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.[3]
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, 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.

In this project, we plan to work 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 user of grid services.

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.

5.4.2 Metric Down-Selection Process

The long list of potential flexibility metrics will be reduced to fewer than a dozen key metrics for detailed evaluation and analysis. Because we believe that not all metrics are universally applicable for all stakeholders, the metric down-selection process will be driven by stakeholders engaged in the use cases (CAISO, ERCOT, or both). Because CAISO has a significantly larger proportion of solar generation than ERCOT, different flexibility metrics may be chosen for the two ISOs. The ultimate down-selection goal is to identify two or three key leading and lagging metrics for demand, supply, and market efficiency.

[3] http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=9282

5.4.3 Statistical Analysis for Lagging Metrics

Historical data from CAISO and ERCOT archives can be used to infer insufficient system flexibility. For example, wind and solar curtailment coincident with generators at their maximum or minimum output or fully loaded transmission lines may indicate insufficient flexibility if there are no coincident failures in the system. We plan to work with stakeholders to identify the frequency and magnitude of these conditions in the historical data and summarize general trends. The costs of these events can also be estimated. Similar analyses of the other metrics described in Section 5.4.1 can be conducted.

5.4.4 Use of Production Cost Models to Assess Flexibility

Production cost models can be used to evaluate a number of 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—are required to be online to meet the electricity demand and supply reserves for operational reliability, and 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 (metrics 1 and 2). 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.

An example of the application of a production cost model to evaluating system flexibility is shown in Figure 5.3 and Figure 5.4 using three different flexibility metrics—renewable curtailment, operational savings, and 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.

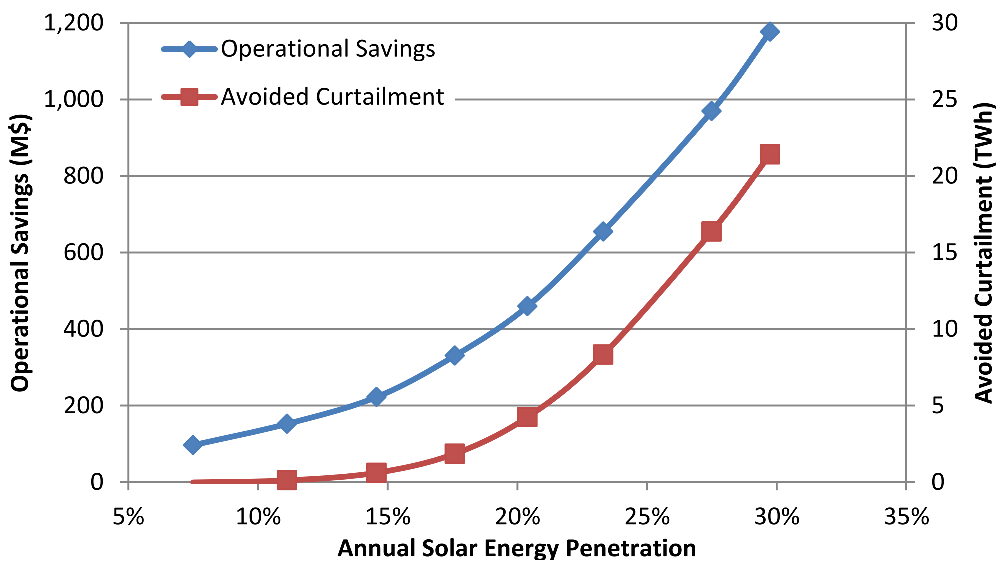

Figure 5.3. Operational savings and curtailment reduction associated with added flexibility.

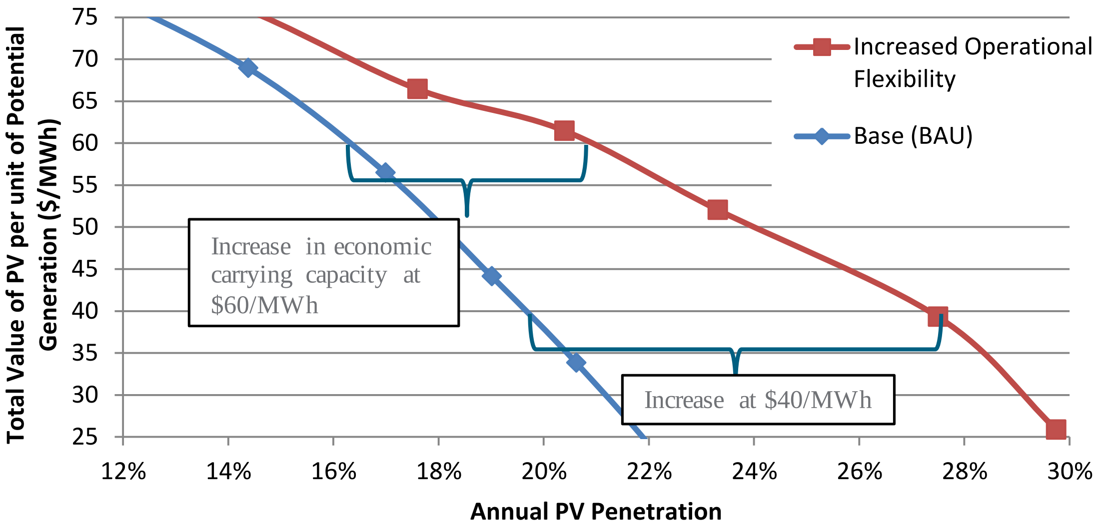

Figure 5.4. Increase in economic carrying capactiy resulting from increased operation flexibility.

Figure 5.3 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. 2015). Fundamentally, an ECC results from the decline in the value of renewables as they are added to the grid (Mills and Wiser 2012). Figure 5.4 shows the decline in value 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 5 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 8 percentage points from about 20% to about 28%.

5.5 Linkages to Other Metrics

Flexibility is linked to reliability, sustainability, and affordability. While reliability measures resource adequacy to meet system peaks under possible contingencies, flexibility measures the ability of the system to ramp resources at a sufficient rate to maintain system stability. It can be challenging to separate these two factors when conducting planning studies with production cost models to attribute loss of load to capacity or flexibility.

Flexibility is also linked to sustainability. Many stakeholders are conducting renewable integration studies to determine how much intermittent wind and solar generation can be integrated into the system without imposing an unacceptable cost or reliability burden. System flexibility is a key focus of these studies.

5.6 Scope of Applicability

In general, system flexibility must be managed by stakeholders at balancing authority areas (BAAs), regional transmission organizations, and ISOs. Hence, this level of aggregation is most relevant and useful. The same metrics could be applied to higher levels of aggregation (regional and national), but appropriate standards using these metrics that should be used for planning or historical performance assessment may differ because of differences in operating environments. For example, one ISO may have substantially more renewable penetration than another. The ISO with more renewables would need to have set much higher levels on the flexibility metrics than similar ISOs with fewer renewables.

5.6.1 Asset, Distribution, Bulk Power Level

Distribution-level resources may act autonomously to provide flexibility to the system (e.g., NEST thermostats). However, flexibility is generally managed at higher levels of aggregation. Hence, flexibility metrics are not very relevant at this low level.

5.6.2 Utility Level

Metrics representing flexibility potential in demand response and interruptible tariffs can help capture flexibility attributes that are typically aggregated to the utility level. These resources are generally incorporated in production cost models in a very aggregated way. Flexibility metrics are applicable at this level.

5.6.3 State Level

Because states generally have a few utilities, flexibility metrics are applicable at this scale. In addition, larger states have ISOs within the state boundary (ERCOT, CAISO, NYISO). It is at the ISO level of aggregation that flexibility metrics become most useful.

5.6.4 Regional Level

Flexibility metrics are also very relevant for planning and operations at the larger, multi-state ISOs (e.g., MISO, PJM, and ISO-NE).

5.6.5 Interconnect Level

Flexibility metrics are also relevant at the Eastern and Western Interconnect levels. Administratively, it is difficult to coordinate stakeholder efforts to conduct integrated planning and operations studies at this level.

5.6.6 National Level

Although flexibility metrics can be aggregated to this level to track over all progress, flexibility is generally not managed across multiple interconnects due to the limited capacities of ties for power transfer.

5.7 Use-Cases for Flexibility Metrics

5.7.1 Improving Distribution System Metrics

The transmission system use-case will incorporate flexibility characteristics of the distribution system. However, no use-cases are planned to demonstrate new flexibility metrics for application at the distribution level.

5.7.2 Improving Transmission System Metrics

Potential use-cases for these metrics are summarized in

Table 5.1. The first three rows in the table identify partners who would help develop and refine metrics. We have already engaged these stakeholders to help develop the candidate metrics previously described. The last two rows identify partners who would provide data for the use-cases. We have also engaged these stakeholders to assess the availability of data from their systems and to seek their input on the metrics. This report marks the completion of Year 1 of the project. In Year 2 of the project, the use-cases would focus on adaptation of existing metrics, development of new metrics, and application of them to historical data provided by ERCOT, CAISO, their respective Public Utilities Commissions (PUCs), utilities, and other stakeholders. These use-cases would provide lagging indicators of progress toward grid modernization.

Table 5.1. Flexibility use-case partners, work scope, and schedule.

Partner	Description of Work	Time Frame
FERC	Adapt metrics described in FERC's Common Metrics Report (FERC 2016) to the ERCOT system. Collaborate to develop, refine, and apply additional metrics to ERCOT and CAISO systems.	Year 2, 3
PG&E	Illustrate how production cost modeling methods developed by PG&E and Astrape Corp. can be applied to ERCOT and CAISO. Collaborate to develop, refine, and apply additional metrics to ERCOT and CAISO systems.	Year 2, 3
EPRI	Apply metrics developed by EPRI to the ERCOT and CAISO systems. Collaborate to develop, refine, and apply additional metrics.	Year 2, 3
CAISO	Acquire historical data and results of planning studies with models to illustrate use of metrics.	Year 2, 3
ERCOT	Acquire historical data and results of planning studies with models to illustrate the use of metrics.	Year 2, 3

Year 3 would focus more on the use of models to develop new metrics and to provide the same function as metrics. In Year 1 of the project, some stakeholders indicated that the issue of flexibility is so complicated that a metric—a simple algebraic expression using static properties of the system—cannot provide reliable, actionable information. Rather, production cost, reliability, load flow, and weather models of the system are needed to determine whether the current or proposed system is sufficiently flexible to accommodate variability and uncertainty in net load. We would work with ERCOT, CAISO, and other stakeholders to exercise existing models to derive methods and heuristics to guide system design, operation, and market structure, and to support policy analysis.

ERCOT and CAISO were selected as potential partners for use-cases because of their high levels of renewable penetration and related system flexibility challenges. Metrics that can effectively characterize flexibility in these systems are likely to be useful in less demanding environments that have lower renewable penetration.

Although distribution-level resources such as demand response are captured by the metrics, most of the metrics would be more useful for planning and operations at the transmission level. Results from emerging probabilistic planning methods will be used where available.

5.7.3 Probabilistic Enhancement of Transmission Planning Metrics

The transmission system use-case will incorporate probabilistic factors such as generator and transmission line outages as well as forecast errors. However, no use-cases are planned to demonstrate new probabilistic transmission system planning metrics.

5.8 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 solely based on the urgency that RTOs/ISOs have expressed to better understand the flexibility requirements to address 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 is sufficient, and 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 to find 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 further 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, addressing questions of 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.

6.0 Sustainability

Sustainability is often defined as including three pillars: environmental, social, and economic. Given the other categories of metrics defined for the GMLC1.1 project, we focus sustainability within GMLC1.1 as *environmental sustainability*. Further, there is a continuum of environmental sustainability metrics from environmental stressors (e.g., greenhouse gas [GHG] emissions) to effects on the environment (e.g., global surface temperature increase) to impacts on humans and the environment (e.g., increased incidence of mosquito-borne diseases). The challenge increases for determining the causality of impacts as one moves from stressors to impacts because multiple causes could be responsible for any given impact (e.g., the health of U.S. citizens). In this GMLC1.1 project, we will consider environmental stressors.

6.1 Definition

Sustainability is defined for GMLC 1.1 as the "provision of electric services to customers minimizing negative impacts on humans and the natural environment." Environmental Sustainability is further defined in GMLC 1.1 as "provision of electric services to customers minimizing negative impacts on the natural environment and human health." We focus GMLC 1.1 on environmental sustainability and in year 1 on assessing metrics for GHG emissions from electricity generation.

6.2 Established Metrics

Although numerous mature metrics could be used to assess the environmental sustainability of the electrical grid, they are not necessarily tailored to the electric power sector and they almost all evaluate past performance (lagging metrics) rather than predicting future performance (leading metrics). As a result, it is important to critically examine these established metrics and evaluate their potential for assessing changes in environmental sustainability as the grid evolves.

As an example of the breadth of environmental sustainability metrics (described further below), the EPRI identified 249 individual metrics of environmental sustainability that electric utilities have been asked to report through voluntary (corporate) reporting programs (EPRI 2014b). Many of these metrics were established decades ago to comply with federal laws like the Clean Air Act (42 U.S.C. § 7401 et seq. [1970]), Clean Water Act (33 U.S.C. § 1251 et seq. [1972]), the Resource Conservation and Recovery Act (42 U.S.C. § 6901 et seq. [1976]), and their implementing regulations. These metrics generally measure environmental stressors like air pollutant emissions (GHG and non-GHG pollutants like nitrogen and sulfur oxides, particulate matter, etc.), pollutant discharges to water, land-use changes, and depletion of natural resources, which can then be used (generally via modeling) to assess the impact on the environment and human health (e.g., potential changes in the global surface temperature).

Because the established environmental sustainability metrics are so numerous and diverse, the first year of the GMLC1.1 project focused on an environmental sustainability issue chosen for its maturity of definition, multiple available data products, and availability of baseline data: GHG emissions. GHG emission metrics can be classified into two main reporting categories: federal and non-federal referred to as voluntary. The following discussion provides examples of these two types of established GHG emission metrics. Note that the discussion is not meant to be all-inclusive because there are more metrics even for GHG emissions alone than are possible to include in this reference document.

During the second year of the GMLC1.1 project, the relevance of these GHG emission metrics is proposed to be assessed in the context of specific use-cases (further discussed in Section 6.5). In addition, a new metric is proposed to be developed to better quantify the relationship between power sector water use and availability (see Section 6.3), and additional assessment of existing metrics is proposed with regard to criteria air pollutant emissions.

6.2.1 Federal GHG Emissions Metrics

The U.S. Environmental Protection Agency (EPA) and the EIA are the two primary federal agencies that report GHG emissions from the electric power sector. However, between these two agencies, at least eight data products use one or more of several primary data sources to report estimates of GHG emissions (Table 6.1). The primary purpose of these data products varies from satisfying federal regulations to providing information for forecasting future emissions. Six data products report only carbon dioxide (CO_2) emissions, while two report emissions for more than one GHG (i.e., CO_2, nitrous oxide [N_2O], and methane [CH_4]) and/or carbon dioxide equivalents (CO_2e). The lowest level of spatial resolution is at the unit (e.g., boiler) level and the lowest level of temporal resolution is hourly.

Table 6.1. Summary of eight federal data products produced by the EPA and the EIA to report GHG emissions from the electric power sector.

Data Product	Primary Purpose	GHGs Included	Spatial Resolution for Electric-Sector Emissions	Temporal Resolution for Electric-Sector Emissions	Time Range	Reporting Lag
EPA GHG Inventory[(a)]	To develop an economy-wide GHG inventory	CO_2, N_2O, CH_4, HFCs, PFCs, SF_6, NF_3	National	Annually	1990-2014	2 years
EPA GHG Reporting Program[(b)]	To satisfy federal regulations by tracking historical GHG emissions from industrial sectors listed in the Mandatory GHG Reporting Rule[(i)], e.g., power plants	CO_2, N_2O, CH_4, HFCs, PFCs, SF_6, NF_3, and other GHGs	Facility	Annually	2010-2015	1 year
EPA eGRID[(c)]	To provide a comprehensive source of historical electricity data to the public	CO_2, N_2O, and CH_4	Unit within facility, entire facility, state, balancing authority, eGRID sub-region, NERC region, and national	Typically every 2 to 3 years	1996-2014 (with several gaps)	18 months
EPA Clean Air Markets Program[(d)]	To satisfy federal regulations by tracking historical emissions from power plants	CO_2	Unit within facility, entire facility, state, EPA region, and national (only includes the 48 contiguous states)	Hourly, daily, monthly, quarterly, annually	1980-2016	0-4 months
EIA Electric Power Annual[(e)]	To provide historical, energy-related information to the public	CO_2	State and national, with facility-level supplements available upon request	Annually	1994-2015	9 months
EIA Monthly Energy Review[(f)]	To provide historical, energy-related information to the public	CO_2	State and national, with facility-level supplements available upon request	Monthly	1973-2017	1 month
EIA Annual Energy Outlook[(g)]	To forecast long-term energy usage	CO_2	Census region and national	Annually	1993-2050	1 year
EIA Short-Term Energy Outlook[(h)]	To forecast short-term energy usage	CO_2	National	Monthly, quarterly, annually	2009-2018	1 month

References: (a) EPA 2015b; (b) EPA 2016e; (c) EPA 2015a; (d) EPA 2016b; (e) EIA 2016b (f) EIA 2016c (g) EIA 2017a; (h) EIA 2017b; (i) EPA 2013

These federal data products use two main types of metrics to report GHG emissions from the electric power sector (Table 6.2): absolute GHG emissions (mass emissions); and GHG emissions intensities (e.g., mass emissions per unit of generation). The data products estimate these GHG emission metrics using one of three calculation methods:

- multiplying fuel consumption by a fuel-specific emission factor (mass of GHG emitted per unit of fuel consumed)—covered in Section 6.2.1.1,
- directly measuring emissions via continuous emission monitoring systems (CEMSs)—covered in Section 6.2.1.2, or
- a combination of these two methods.

The following sections provide further detail about these two main calculation methods.

Table 6.2. List of electric-sector GHG emission data reported by federal data products.

Metric Name	Definition	Calculation Method
GHG emissions from GHGRP	Absolute GHG emissions (metric tons of CO_2, CH_4, and N_2O) as reported to the EPA under a mandatory facility Greenhouse Gas Reporting Program (GHGRP)	Primarily measured via CEMS
GHG emissions from GHGI	Absolute GHG emissions (metric tons of CO_2e) as estimated by the EPA's Greenhouse Gas Inventory (GHGI)	Relies on primary data from EIA's Monthly Energy Review (MER) and other data sources
GHG emissions from eGRID	Absolute GHG emissions (short tons of CO_2 and CO_2e; pounds of N_2O and CH_4) as compiled by the EPA's Emissions and Generation Resource Integrated Database (eGRID)	Collection of primary data from EIA's MER and EPA's Clean Air Markets Program (CAMP) and other data sources
GHG emissions intensity from eGRID	GHG emissions intensity (pounds of CO_2, N_2O, CH_4, and CO_2e per unit of generation (MWh or GWh) or per unit of heat input (mmBtu)) as estimated in the EPA's eGRID	Collection of primary data from EIA's MER and EPA's CAMP and other data sources
CO_2 emissions from CAMP	Absolute CO_2 emissions (short tons of CO_2) as reported by the EPA's CAMP based on mandatory reporting of CO_2 emissions (only includes units in the 48 contiguous states that serve a generator >25 MW)	Primarily measured via CEMS
CO_2 emissions from MER	Absolute CO_2 emissions (metric tons of CO_2) as compiled in the EIA's MER	Estimated via fuel consumption data from EIA-923 and EIA-compiled emission factors
CO_2 emissions from EIA's EP Annual	Absolute CO_2 emissions (metric tons of CO_2) as compiled in the EIA's Electric Power Annual (EP Annual) (includes emissions from combined heat and power)	Estimated via fuel consumption data from EIA-923 and EIA-compiled emission factors
CO_2 emissions from EIA's STEO	Absolute CO_2 emissions (metric tons of CO_2) as projected in the EIA's Short-Term Energy Outlook (STEO)	Estimated via fuel consumption projections from the National Energy Modeling System (NEMS) and EIA-compiled emission factors
CO_2 emissions from EIA's AEO	Absolute CO_2 emissions (metric tons of CO_2) as projected in the EIA's Annual Energy Outlook (AEO)	Estimated via fuel consumption projections from NEMS and EIA-compiled emission factors

6.2.1.1 Calculating GHG Emissions via Fuel Consumption

Definition

According to the Intergovernmental Panel on Climate Change (IPCC 2006), the equation for calculating GHG emissions from fuel consumption is given by

$$E_{GHG,fuel} = FC_{fuel} \times EF_{GHG,fuel}$$

where $E_{GHG,fuel}$ equals the amount of GHG emissions (in kilograms) generated by a particular fuel type, FC_{fuel} is the amount of fuel combusted (in TJ), and $EF_{GHG,fuel}$ is the emission factor for a given *GHG* (in kg/TJ) by type of fuel, which, for CO_2, includes the fuel-specific fraction of carbon that is oxidized during combustion (for CO_2, the IPCC assumes that the oxidation factor is 1 for all fuel types).

The total emissions of a specific GHG are then calculated by summing over all fuel types as follows:

$$E_{GHG} = \sum_{fuels} E_{GHG,fuel}$$

The level of detail of the above equations can be further increased to compute the emissions by combustion technology, not just fuel type. The specificity of the equations can also be decreased to use country-specific (rather than fuel-specific) emission factors.

Maturity Level

This measure has been well known and applied for decades, but improvements in scientific understanding occasionally adjust emission factors, fuel carbon content, the measurement of fuel consumption, and other factors.

Applications

A variety of stakeholders, including the EIA and the EPA, estimate GHG emissions using fuel consumption data. To do so they use a combination of U.S.-specific and IPCC default emission factors, as appropriate for the specific application.

Data Source and Availability

Sources of GHG emissions from the electric sector that rely completely or partially on fuel consumption-based methods include the EIA Monthly Energy Review (MER; lagging), the EIA Annual Energy Outlook (AEO; leading), the EIA Electric Power (EP) Annual (lagging), the EIA Short-Term Energy Outlook (STEO; leading), the EPA GHG Inventory (lagging), and the EPA Emissions and Generation Resource Integrated Database (eGRID; lagging).

6.2.1.2 Measuring GHG Emissions via Continuous Emission Monitoring Systems

Definition

The EPA's Clean Air Markets Program (CAMP) oversees several market-based air-quality programs, including the Acid Rain Program (EPA 2016a) and the Cross-State Air Pollution Rule (EPA 2016d). If a facility is regulated by one of these programs, it must monitor and report hourly emissions of sulfur dioxide (SO_2), CO_2, and nitrogen oxide (NO_x) as well as operation data such as heat input and electrical or steam output. These data are reported under the authority of Title 40 of the *Code of Federal Regulations* Part 75 (40 CFR Part 75) continuous emission monitoring rule (EPA 2009) and are accessible using the CAMP (EPA 2016b). These data are also used by some states to implement the Regional Greenhouse Gas Initiative (RGGI 2016).

The monitoring and reporting requirements for CEMSs vary by several factors including pollutant type, source type, and technology type (EPA 2016c). For example, if CO_2 is measured using a CO_2 analyzer on a wet basis, the emissions need to be calculated using

$$E_h = K * C_h * Q_h$$

where

E_h = the hourly CO_2 mass emissions (in tons per hour),
K = a conversion factor of 5.7×10^{-7} (tons per standard cubic foot per percent CO_2),
C_h = the hourly average CO_2 concentration (percent CO_2 on a wet basis), and
Q_h = the hourly average volumetric flow rate (in standard cubic feet per hour on a wet basis).

However, if CO_2 is measured using a gas or oil fuel flow meter, then the emissions must be computed using

$$W_{CO_2} = \frac{F_c * H * U_f * MW_{CO_2}}{2000}$$

where

W_{CO_2} = the amount of CO_2 emitted (in tons per hour),
F_c = the carbon-based fuel emission factor, which represents the ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (in standard cubic feet of CO_2 per mmBtu),
H = the hourly heat input rate (in mmBtu per hour),
U_f = is the number of standard cubic feet of CO_2 per lb-mol, which is equal to 1/360 at 14.7 psi and 68°F, and
MW_{CO_2} = the molecular weight of carbon dioxide (44.0 lb/lb-mol).

Maturity Level

This measure has been well known and applied for decades.

Applications

The EPA requires most facilities with a generating capacity above 25 MW to report GHG emissions via CEMSs (EPA 2009). Other provisions also require certain facilities that emit 25,000 or more metric tons of CO_2e per year (of any generating capacity) to report data via CEMSs (EPA 2013).

Data Source and Availability

Many federal sources use CEMS data in developing their estimates of GHG emissions, including the EPA GHG Reporting Program (lagging), the EPA eGrid (lagging), and the EPA CAMP (lagging).

6.2.1.3 Challenges

Each of the eight federal electric-sector GHG data products has its own specific purpose, scope, and methods (see Table 6.1 for a high-level summary). It is not the intent of this analysis to suggest that the estimates provided by these data products are not accurate or that they do not meet their intended purpose. Rather, we find the communication of the results challenging to overlapping audiences of analysts, investors, intervenors, decision-makers and the general public, for whom the subtleties of legitimate differences between the data products are important for proper interpretation and use of the GHG emission data. At least four of these data products are publicly communicated as representing "electric-sector CO_2 emissions" (EIA 2015, 2017b; EPA 2016f, 2017a), yet the difference between estimates in a given year is up to 9.4% (Eberle and Heath, paper in preparation).

The absolute differences among these data products are not an indication of uncertainty. Instead, variation in the data products' scopes (e.g., threshold for inclusion of facilities such as capacity, which fuel types are tracked [e.g., biomass]) and other factors lead to disparities in coverage, which result in different estimates of CO_2 emissions. For example, the EPA's CAMP data are the lowest because they only account for emissions from units that supply generators above 25 MW, and the EIA's Electric Power (EP) Annual is the largest because it includes emissions from combined heat and power.

When this project began, no objective and comprehensive review of the landscape of federal GHG emission estimation products was available. Thus, it was a valuable function of GMLC1.1 to develop such a critical review (Eberle and Heath, paper in preparation).

6.2.2 Voluntary GHG Emission Metrics

In addition to federal GHG emission metrics, dozens of voluntary sustainability reporting programs include GHG emission metrics. Beyond voluntary corporate social responsibility and integrated reporting, the following four long-standing voluntary reporting programs are generally accepted by the electric power industry (according to EPRI 2015b):

- The Climate Registry
- CDP (formerly the Carbon Disclosure Project)
- Dow Jones Sustainability Index
- The Global Reporting Initiative.

These reporting programs only represent a small portion of all voluntary reporting programs (EPRI 2015b).

6.2.2.1 Definition

EPRI performed a thorough review of voluntary sustainability reporting programs and identified an extensive list of existing metrics that have been used and/or applied to the electric utility industry (EPRI 2014b). They performed this analysis with respect to 15 material sustainability issues that included all three pillars of sustainability (environment, social, and economic). GHG emissions were one of the six material issues that they examined within the pillar of environmental sustainability.

The goals of the EPRI study were to identify a comprehensive set of existing metrics for utility benchmarking and to understand the purpose of each metric (EPRI 2014b). By interviewing 52 individuals at 29 different utilities and developing a database of metrics, EPRI was able to identify 448 different metrics for all 15 material sustainability issues. Of these, 249 mapped to environmental sustainability, and 78 of these reported CO_2 or CO_2e emissions. For these GHG emission metrics, only two were leading, while 76 were lagging. The complete database of metrics identified by EPRI is not publicly available. However, with feedback from stakeholders, EPRI down-selected the metrics that are most relevant, cost-effective, and scientifically defensible for the purpose of benchmarking sustainability performance in the electric power industry (EPRI 2016a, 2017). Through this process, EPRI reduced the number of relevant environmental sustainability metrics down to 55, out of the 249 originally identified. The 12 metrics identified for GHG emissions are listed in Table 6.3 (please refer to EPRI 2016a and 2017 for detailed documentation of these metrics).

In addition to the metrics outlined by EPRI, the Sustainability Accounting and Standards Board (SASB) has developed a provisional sustainability accounting standard for electric utilities (SASB 2016). This standard includes total Scope 1 emissions, which are also included in EPRI's list of metrics for benchmarking GHG emission performance, and also describes five other metrics (Table 6.3). Four of the additional metrics defined by the SASB are percentages of emissions covered by 1) emissions-limiting[1] and 2) emissions-reporting[2] regulations; 3) percentages of customers served in markets subject to RPSs; and 4) percentage fulfillment of RPS targets by market. The fifth metric is a qualitative metric that describes the long- and short-term strategies for managing emissions, meeting emission-reduction targets, and evaluating performance against those targets.

Table 6.3. Voluntary metrics used to assess GHG emissions from the electric power industry as reported by the Electric Power Research Institute (EPRI 2016a) and the Sustainability Accounting and Standards Board (SASB 2016).

Metric Name	Definition	Calculation Method	Organization
Total CO_2 emission rate for net generation from coal	GHG emissions intensity for company, equity-owned coal net generation in metric tons CO_2 per MWh	Unspecified[(a)]	EPRI
Total CO_2 emission rate for net generation from natural gas	GHG emissions intensity for company, equity-owned natural gas net generation in metric tons CO_2 per MWh	Unspecified[(a)]	EPRI

[1] Emissions-limiting regulations are intended to limit or reduce emissions (e.g., cap-and-trade programs, carbon tax systems, emissions control and permit-based systems).
[2] Emissions-reporting regulations require the disclosure of data, but do not impose limits, costs, targets, or controls on the amount of emissions generated.

Table 6.3. (contd)

Metric Name	Definition	Calculation Method	Organization
Total CO_2 emission rate for net generation from oil	GHG emissions intensity for company, equity-owned oil net generation in metric tons CO_2 per MWh	Unspecified[(a)]	EPRI
Total CO_2 emission rate for net generation from fossil fuel	GHG emissions intensity for company, equity-owned fossil-fueled net generation in metric tons CO_2 per MWh	Unspecified[(a)]	EPRI
Total CO_2 emission rate for net generation from biopower	GHG emissions intensity for company, equity-owned biomass-fueled net generation in metric tons CO_2 per MWh	Unspecified[(a)]	EPRI
Total CO_2 emissions rate for total net generation	GHG emissions intensity for all company, equity-owned net generation (i.e., full fleet) in metric tons CO_2 per MWh	Unspecified[(a)]	EPRI
Total CO_2 emissions rate for power deliveries	GHG emissions intensity for power deliveries to a utility's customers (i.e., equity-owned generation and power purchased power) in metric tons CO_2 per MWh	Unspecified[(a)]	EPRI
Total Scope 1 CO_2e emissions	Total mass of GHG emissions from all direct company operations in metric tons of CO_2e	EPRI: The Climate Registry's General Reporting Protocol[(b)] SASB: The World Resources Institute's GHG Protocol[(c)]	EPRI and SASB
Total Scope 1 CO_2e emissions intensity	GHG emissions intensity from all direct company operations in metric tons of CO_2e per MWh	Unspecified	EPRI
Total Scope 1 and 2 CO_2e emissions	Total mass of GHG emissions from all direct operations (Scope 1) plus indirect operations from the consumption of purchased electricity, heat, or steam (Scope 2)	General Reporting Protocol[(b)]	EPRI
Total Scope 1 and 2 CO_2e emissions intensity	GHG emissions intensity from all direct operations plus indirect operations from the consumption of purchased electricity, heat, or steam in metric tons CO_2e per MWh	Unspecified	EPRI
Total Scope 3 CO_2e emissions	Total mass of GHG emissions associated with upstream and downstream emissions from a customer's supply chain	General Reporting Protocol[(b)]	EPRI

Table 6.3. (contd)

Metric Name	Definition	Calculation Method	Organization
GHG emissions covered by emissions-limiting regulations	Percentage of Scope 1 emissions covered under emissions-limiting regulations	SASB Electric Utilities Standard[(d)]	SASB
GHG emissions covered by emissions-reporting regulations	Percentage of Scope 1 emissions covered under emissions-reporting regulations	SASB Electric Utilities Standard[(d)]	SASB
Customers in markets subject to renewable portfolio standards (RPSs)	Number of customers served in markets subject to RPSs	SASB Electric Utilities Standard[(d)]	SASB
Fulfillment of RPS target	Percentage fulfillment of RPS target by market	SASB Electric Utilities Standard[(d)]	SASB

Notes: (a) Likely calculated using data reported to federal sources in Table 6.1; (b) The Climate Registry 2013; (c) WRI/WBCSD 2004; (d) SASB 2016.

6.2.2.2 Maturity Level

These voluntary metrics vary in maturity, but they are more recent than the federal GHG data products' metrics. However, in some cases, these voluntary metrics rely on the established methods used for federal GHG emission metrics.

6.2.2.3 Applications

Electric utilities may choose to report information about their GHG emissions to voluntary programs in order to benchmark against peers, increase stakeholder communication/engagement, and measure/improve their own performance (EPRI 2014b).

6.2.2.4 Data Source and Availability

Data sources include The Climate Registry, the CDP, the Dow Jones Sustainability Index, the Global Reporting Initiative, corporate social responsibility reports, and integrated (comprehensive sustainability and financial) reports.

6.2.2.5 Challenges

There are two major challenges with voluntary reporting schemes: data availability and methodological transparency. With regard to availability, many voluntary reporting schemes are proprietary or, if publicly released, only report aggregated data (not total GHG emissions), which will make them challenging to use in the GMLC context. Furthermore, the calculation methods for these metrics are often not defined specifically enough to ensure consistency in responses from different utilities.

However, voluntary GHG emission metrics are generally calculated using data reported to the federal sources and many companies use what they report to voluntary reporting schemes in their own corporate sustainability reports and in reports to PUCs (Scott 2016[1]). As a result, mapping the relationship between federal (mandatory) and voluntary reporting will be useful to stakeholders in ensuring clarity, consistency, comparability, and accuracy. One potential use-case that could be explored in the second year of the GMLC1.1 project would be to assess the major linkages, complementarities, and contradictions between voluntary reporting metrics and those reported to federal agencies (see Section 6.4 for details).

6.3 Emerging and Future Metrics

Because of the abundance and diversity of established environmental sustainability metrics, one purpose of the first year of GMLC1.1 was to catalog, characterize, critically compare, and synthesize the available federal GHG emission metrics for applicability and utility for electric grid actors in the context of a modernizing grid. This work involved evaluating the ability of established federal GHG metrics to capture changes in emissions that might result from grid modernization and to assess the need for developing new metrics or modifying existing metrics to better capture future emissions. The results of this work are summarized in Section 6.3.1, and details are provided by Eberle and Heath (paper in preparation). Furthermore, in Years 2 and 3, we plan to develop a new water intensity metric; details about the proposed metric are provided in Section 6.3.2.

6.3.1 Federal GHG Emission Metrics in the Context of Grid Modernization

Grid modernization may affect the accuracy of established GHG emission data products because the generation mix may change, wherein certain energy sources that emit GHGs that are not currently captured by these metrics could increase. We evaluated the potential coverage gaps that might result for each of the eight federal data products outlined in Table 6.1. We found that none of the current data products are currently able to fully allocate the electric-sector portion of CO_2 emissions from several energy sources that are projected to grow in the future: biomass, energy storage, CHP , and small-scale, fossil-fueled distributed generation (Eberle and Heath, paper in preparation).

The EIA's AEO, the EIA's MER, the EPA's eGRID, and the EPA's Greenhouse Gas Inventory (GHGI) are the four most comprehensive data products in terms of estimating CO_2 emissions from the growing generation sources listed above, and attributing their emissions to the electric sector. Whereas each data product as a whole may capture some, if not all, of the CO_2 emissions from CHP, biomass, energy storage, and small-scale distributed generation, no data product is able to fully allocate to the electric sector the portion of these emissions that are attributable to electricity generation. For example, the EPA's GHGI considers distributed generation in as much as it reconciles all energy used in the economy, but the GHGI does not attribute these emissions to any specific source, nor does it allocat e emissions from generation sources under 1 MW to the electric power sector. Furthermore, only one of the data products—the EIA's AEO—is currently able to directly attribute some emissions associated with small-scale (less than 1 MW) distributed generation, but these emissions are currently only estimated for specific technologies in the commercial and residential sectors, not the electric power sector as a whole (EIA 2016a). As distributed generation and these other source categories grow in their contribution to total U.S. electricity generation, these data products could misattribute and/or misallocate the CO_2 emissions, which

[1] Scott, M. 2016. Personal correspondence with Morgan Scott, the manager of EPRI's Energy Sustainability Interest Group, regarding GMLC1.1 sustainability efforts and EPRI's report titled Metrics to Benchmark Sustainability for the Electric Power Industry. Phone conversation on December 1, 2016.

could lead to an inaccurate accounting of the electric sector's contribution to national CO_2 emissions and subsequently hinder the prioritization of sources and potentially lead to inefficient allocation of mitigation resources.

While these emission categories currently account for less than 1 percent of electric-sector CO_2 emissions, we show that they could potentially expand to ~2–8 percent of U.S. electric-sector emissions by 2040 (Eberle and Heath, paper in preparation). These results highlight the need for modifying the GHG emission data products (and their data collection surveys) to better capture and allocate electric-sector GHG emissions in the future. We have already started to identify several recommendations for improving these data products (Eberle and Heath, paper in preparation), but this effort will continue in consultation with the federal data product owners during Years 2 and 3 of GMLC1.1 project.

6.3.2 Water Use and Availability

The 2016 Quadrennial Energy Review (QER) highlighted tradeoffs in the energy-water nexus (EWN) as an area worthy of future research (DOE 2015c). The report also noted that "significant regional variability in energy and water systems, their interactions, and resulting vulnerabilities" make addressing EWN issues challenging (EPSA 2017). Existing metrics used in evaluating water usage in the energy sector are inadequate and do not provide a comprehensive assessment of impacts and risks. In particular, water intensity metrics do not consider the total magnitude of the water use or the timing of energy activities; water scarcity definitions are inconsistent from application to application and do not factor in the actual impact of energy activities; and total water use estimates fail to consider water availability. Indeed, a recent EPRI report states specifically that "additional metrics are needed" to fully understand "location based water scarcity," "water risk position," and "regional ecological impacts" of the energy sector (EPRI 2016a).

This effort would build upon recent DOE and EPRI research to develop a new metric, tentatively titled Relative Water Risk (RWR), that addresses water sustainability and impacts for a modernized power grid. The RWR could be used to assess existing and proposed infrastructure and technological investments in the energy sector. Specifically, this metric would quantify the use (both withdrawal and consumption) of water in the context of local and regional water availability. This new metric would improve upon three separate existing metrics (for which data are often available), namely: water intensity (in terms of water use per unit of energy activity), water scarcity and availability (which can have many different definitions), and total water use. This new metric is needed because the existing metrics do not adequately capture the impacts of existing or proposed energy activities in the full context of available water resources, leading to potentially misleading and inconsistent comparisons across regions and technology types.

A RWR metric would build upon recent advancements in estimating water availability and impacts of energy technology activities to provide a more comprehensive assessment of the sustainability of energy activities in the context of regional water availability. The development of this metric aligns with the stated research goals in the QER, which advocate additional research in alternative cooling systems and carbon capture and storage systems, both of which can have significant impacts on power plant water requirements. This new metric would allow for a consistent, transferrable comparison among different technology advancements in different regions to better assess the sustainability of future investments, and is complementary to (and non-duplicative of) DOE Water Energy Technology Team initiatives.

The effort to develop this metric would involve extensive stakeholder engagement with a diverse set of participants (e.g., Western States Water Council, state-level water managers and engineers, energy industry, environmental non-governmental organizations, and federal agencies) through at least one regional workshop. This stakeholder engagement activity would build upon existing contacts the sustainability team has developed related to characterizing water availability and differences in water rights regimes across the country. In addition, this effort would consider two relevant case studies with interested stakeholders to demonstrate the feasibility and usefulness of an RWR metric. Case studies would consider diversity in location, energy activity, and/or water rights structures, and would build upon existing contacts and ongoing projects.

6.4 Scope of Applicability

The GHG emission metrics assessed in Year 1 of the GMLC1.1 project are applicable across a wide range of spatial scales.

6.4.1 Asset, Distribution, and Bulk Power Level

Two of the federal GHG data products—the EPA's eGRID and CAMP—report emissions at the asset (generator/boiler) level. eGRID also reports GHG emissions at the balancing authority level.

6.4.2 Utility Level

The data reported by the voluntary reporting programs are often reported at the utility level. In addition, all but three of the federal GHG data products report emissions at the facility level, which could be aggregated to the utility level. These data products include the EPA's eGRID, GHGRP, and CAMP, and the EIA's EP Annual and MER. However, utility-level aggregation of these data may be difficult because small and medium facilities have units that are owned by multiple utilities and the ownership of these units changes frequently through purchases, mergers, and closures.

6.4.3 State Level

Voluntary GHG emission metrics are generally not reported at the state level. While the data from these voluntary metrics could be aggregated to the state level, it could be challenging for these metrics to capture all electric-sector GHG emissions at this level because voluntary metrics are compiled at the utility level and not all utilities report these voluntary metrics. However, all but two of the federal data products (the EPA's GHGI and the EIA's STEO) report data at the state level.

6.4.4 Regional Level

Similar to state-level metrics, voluntary GHG emission metrics are not generally reported at a regional level. It might be possible to aggregate the voluntary data to the regional level but the accounting would likely be incomplete. However, three federal data products explicitly report GHG emissions at a regional level: 1) EPA's CAMP reports at the EPA regional level, 2) EIA's AEO reports data by Census region, and 3) EPA's eGRID reports at the NERC regional and eGRID sub-regional levels[1]. In addition, all but two of the federal data products (the EPA's GHGI and the EIA's STEO) report data in a manner that could be summarized at a regional level.

[1] An eGRID sub-region represents a portion of the U.S. power grid that is contained within a single NERC region and generally consists of one or more power control areas (PCAs) that have similar emissions and resource mix characteristics.

6.4.5 National Level

All of the federal GHG emission metrics are reported in a manner that allows for aggregation at the national level, albeit with different boundaries and scopes of emission sources, GHGs, and other factors that result in differences in the estimate of total U.S. electric-sector CO_2 emissions. Because of their utility-specific boundaries, the voluntary GHG emission metrics are not well suited to this level of aggregation.

6.4.6 Other Level

The data reported by several of the federal GHG emission data products could be aggregated to a variety of other levels, such as by city or zip code, based on power supplied to that area. For example, the EPA's Power Profiler web tool (EPA 2017b) uses eGRID data to provide users with estimates of emission intensities based on their distribution company's service area.

6.5 Use-Cases for Metrics

The following sections outline three potential use-cases for GHG emission metrics. Based on continued conversations with stakeholders and collaborators, along with further refinement of the use-case specifics, one of the following three options will be selected for implementation during Years 2 and 3 of the project.

6.5.1 Comparing Federal and Voluntary GHG Emission Metrics

As outlined in Sections 6.2.1.3 and 6.2.2.5, several differences exist across the current federal and voluntary GHG emission metrics. One potential use-case would be to examine the intersection, complementarities, and contradictions between federal reporting of GHG emissions and voluntary reporting for utilities. This use-case would be performed in collaboration with EPRI's Energy Sustainability Interest Group (comprising more than 40 members from electric power companies). One outcome of the use-case would be greater clarity for utilities, regulators, and policy-makers regarding the methods and metrics used across the breadth of federal and voluntary GHG reporting data products.

6.5.2 Quantifying GHG Emission Reductions with Increased Deployment of Renewable Energy in Remote Locations

The GMLC Regional Partnership Project 13, titled the Alaska Microgrid Partnership, is developing a framework to help a village in Alaska reduce diesel consumption by 50 percent without increasing system cost and while also improving system reliability, security, and resilience. This use-case would involve working with the GMLC Regional Partnership to quantify emission reductions associated with the off-grid village's shift from diesel to renewable energy. This work would be done in collaboration with the Alaska Center for Energy and Power and Alaska Energy Authority. The outcomes of this use-case would be 1) an approach for assessing emission reductions and 2) an evaluation of the potential for existing GHG emission metrics to capture emission reductions in the context increased deployment of renewable energy in an off-grid location that uses mostly generators under 1 MW.

6.5.3 Developing Baseline GHG Inventories

Arizona Public Service (APS) Company has approached Arizona State University (ASU) about developing a baseline GHG inventory for APS-wholly owned facilities. This use-case would involve collaborating with the team lead at ASU to assist in the development of a utility-scale baseline GHG inventory. The outcomes of this use-case would be 1) a framework for developing baseline GHG inventories that could rely on federal data products and 2) information for the development of more robust GHG metrics by taking advantage of utility-specific data on small-scale generators.

6.6 Value of Metrics

Stakeholders have provided feedback to the Sustainability Metrics Team about the work they have completed to date, emphasizing its value to their needs. According to the stakeholders, the development of an accurate and unbiased comparison between the various federal data sources will

- provide greater clarity to their users and decision-makers about the federal GHG data products, their methods and proper use;
- help utilities to better understand and communicate the differences in federal and voluntary GHG data reporting to their stakeholders such as PUCs and intervenors; and
- potentially enable wider use of these metrics and thereby improve performance tracking.

By evaluating the federal GHG data products with regard to their ability to discern changes in GHG emissions in the context of a modernizing grid, this work will

- assist federal data product owners in identifying potential improvement opportunities for the existing data products; and
- allow utilities, municipalities, and policy-makers to understand the potential future coverage gaps associated with these established metrics, which may be deemed important in certain contexts.

6.7 Links to Other Metrics

Links to other GMLC1.1 metrics will be explored during this project. For instance, as more flexible resources (such as renewables) are placed on the grid, they will have impacts on existing combustion generators that not only affect their capacity factor but also emission rates during operating hours (e.g., part load, start-up, and shut-down emissions). Such relationships have been explored to some degree in, for instance, renewable integration studies (e.g., Western Wind and Solar Integration Study by Lew et al. 2013), but not at decision-relevant spatial scales.

In the context of the proposed use-cases, additional relationships could be explored with, for instance, reliability, affordability, and resilience.

6.8 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 sustainability metrics definitions, the relevance to the community's needs, and the overall value of 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 EPRI, EPA, EIA, ASU, the National Resources Research Institute (NRRI), and SASB. The following is a synopsis of the key points made during the 1.5 hour briefing:

- Technical considerations:

- Reviewers from the organizations publishing the national GHG emissions data products provided clarification of the scope and similarity of their products. They indicated that we should mention that the differences among the reported historical emissions for the various products are not due to data uncertainty or variability. Differences stem from two data sources.
- To expand the GHG emissions reporting to systems with less than 1 MW, one reviewer suggested talking with APX[1]—provider of technology and service solutions for clients in the energy and environmental markets—about their systems that currently track megawatt-hours of electricity production from utility-scale plants, and see if these systems could be augmented to track GHG emissions as well..
- The potential increases in electrification of energy end-use services could result in increases in electric sector GHG emissions running counter to reduction in overall economy-wide GHG emissions.

- Value of work:
  - Reviewers generally indicated that work completed so far is valuable for the community, and that work in the sustainability area for utilities should continue. The subset of reviewers involved in providing the national GHG data products did not contribute their views on this topic during the meeting.
  - One reviewer who works with the investment community on sustainability issues noted that our work is of value to the investment community.
- Views shared for Year 2 and 3 activities: Individual reviewers provided feedback on the options presented for metrics to pursue in Year 2 and 3 without consensus. The following notions were shared:
  - One reviewer noted the importance of water metrics and the value of integrated planning among electric and water utilities.
  - Land use was identified as an interesting and under-analyzed topic.
  - Determining the health impact of criteria pollutants would be valuable but difficult.

[1] More information available at: http://www.apx.com/about-apx/

7.0 Affordability

Electricity affordability is approached from two perspectives: cost-effectiveness and cost burden. Most established metrics have been developed to determine cost-effectiveness or to answer the question "will a specific investment pay off subject to return on investment criteria?" Emerging metrics determine the electricity service cost burden affecting end-use customers or answering the question "what portion of customers' income or revenue is required to pay for electricity service?"

Electricity affordability implies different things to different stakeholders:

- residential customer: proportion of electricity costs to household income (cost burden)
- commercial/industrial customer: proportion of electricity costs to gross revenue (cost burden)
- PUC: the economic effect of provision of electricity on rate payers, underserved markets, and other stakeholders
- utility: the most prudent (economically efficient) resource investments given the constraints
- merchant: economic efficiency, maximizing returns to owner.

7.1 Definition

The foundational basis for modern grid architecture specification defines affordability as a system quality that "ensures system costs and needs are balanced with the ability of users to pay" (Taft and Becker-Dippmann 2014). Depending on the stakeholder's objectives, electricity affordability is defined either as the quantification of the cost effectiveness of grid investments or the quantification of the burden on customers of the net costs associated with receiving electric service.

Established metrics for cost-effectiveness are acknowledged and documented, but most recent metric development effort has been devoted to defining metrics designed to inform stakeholders and decision-makers about the customer cost burden imposed by the technology investments to achieve the grid modernization. The cost burden connotation recognizes the notion that while grid technology investments may prove to be cost-effective for their investors, the resulting cost burden on customers may or may not be affordable (i.e. costs might exceed the customer's willingness or ability to pay).

7.2 Established Metrics

Several mature metrics that address *cost-effectiveness* look at the affordability question from the standpoint of making investments in new technologies, services, practices, or regulations. Short et. al. (1995) is an often-cited report documenting cost-effectiveness metrics in the energy domain. Some examples include, but are not limited to, the widely accepted examples presented in the following sections.

7.2.1 Levelized Cost of Electricity

7.2.1.1 Definition

The LCOE is the total cost of installing and operating a project expressed in dollars per kilowatt-hour of electricity generated by the system over its life. It translates the string of costs and production over time into a single value, which, if charged to each unit of production, would give the same net present value as the actual cost stream. Some analyses use nominal (inflated) dollars, while others use uninflated or real dollars in the calculation. The simple equation is as follows:

$$LCOE = \frac{NPV(Costs)}{NPV(Production)}$$

Costs can be as simple as construction and operating costs, or can be expanded to include taxes, financing costs, incentives, and salvage value. Production is the total electricity generated in kilowatt-hours over the life of the asset. The NPV (or net present value) of cost is the sum of all costs over the life of the asset with future amounts discounted by a specified discount rate (d):

$$NPV = \sum_{i=0}^{N} Cost_i * (1+d)^{-i}$$

7.2.1.2 Maturity Level

This measure has been well known and applied for decades if not longer.

7.2.1.3 Applications

LCOE has been used for calculating the cost-effectiveness of projects. By incorporating different categories of cash flows, different stakeholder interests can be examined.

7.2.1.4 Data Source and Availability

Publicly recognized data sources include EIA assumptions for the AEO (EIA 2016a) and the data from the National Renewable Energy Laboratory's (NREL's) Annual Technology Baseline (Sullivan et. al. 2015). Individual projects will likely have their own more specific cost data. More detailed cost analysis requires local, state, and federal tax code, incentives information, and general accounting practices.

7.2.2 Internal Rate of Return

7.2.2.1 Definition

Internal rate of return (IRR) is defined as the discount rate that makes the NPV of the cost and revenue stream equal to zero.

7.2.2.2 Maturity Level

This measure has been well known and applied for decades if not longer.

7.2.2.3 Applications

IRR has been used for calculating the cost-effectiveness of projects. By incorporating different categories of cash flows, different stakeholder interests can be examined. Rational investors would undertake projects as ranked by descending IRR order.

7.2.3 Simple Payback Period

7.2.3.1 Definition

Simple payback is defined as the length of time after the first investment that the undiscounted sum of costs and revenues equals zero.

7.2.3.2 Maturity Level

This measure has been well known and applied for decades if not longer.

7.2.3.3 Applications

Simple payback has been used for calculating the cost-effectiveness of projects. While simple to calculate, it does not give as meaningful a result as the NPV or IRR, because it only tells how long it takes until the costs have been recovered, without providing an estimation of the total return. It does not capture any information about the time value of money, nor the impact over the full life of the project.

7.2.3.4 Example

This approach, along with several others, is documented and applied in the analyses supporting federal building energy code implementation (Hart and Liu 2015).

7.2.4 Net Revenue Requirements

7.2.4.1 Definition

Net revenue requirements are defined as the annual stream of revenue necessary to recover the total costs of a project including capital (in the form of depreciation), operating costs including fuel, financing costs including interest and required return on rate on equity, and taxes including both costs and incentives. This is most applicable to regulated utilities that are allowed a regulated rate of return on an approved rate base of investment.

$$RevReq = Fuel + O\&M + Depreciation + Taxes + Return\ on\ Rate\ Base$$

Because these factors will vary over time, the revenue requirements will change and inflation will raise some costs, while depreciation will reduce other categories. Accounting rules, tax incentives, accelerated depreciation, changes in allowed rate of return, life of debt, frequency of rate hearings, adjustment clauses, and other policy and rate-setting factors will all play a role.

7.2.4.2 Maturity Level

Regulated rates and consequent revenue requirement calculations have been in existence for over a century.

7.2.4.3 Applications

Revenue requirements are typically calculated and used on a company-wide basis, but the impacts of single projects on revenue requirements can be calculated by applying the rules on just the subset of costs applicable to the project.

7.2.4.4 Example

The 1992 Energy Policy Act (EPAct 2005) required a study of the tax and rate treatment of renewable energy projects by DOE. Hadley et al. (1993) provided an in-depth analysis.

7.2.5 Avoided Cost

7.2.5.1 Definition

Avoided cost is defined as the net change in the costs of the overall system with the development of the specified project. It can be a complicated calculation, subject to defining the boundaries of the analysis and adequately simulating the system. It captures items such as the energy avoided from other generators because of the new project (either a generator, demand response, or energy efficiency measures), capacity, substation, or transmission and distribution expansion.

7.2.5.2 Maturity Level

This metric is less mature than the other cost-effectiveness metrics described above, partly because of the expanded simulation needed, but it has been used by utilities and regulators for several decades. Environmental assessments that include alternative ways to meet the needs of a project are a more generalized form of avoided cost analysis.

7.2.5.3 Applications

This metric has been used by utilities and regulators for establishing the value of a project compared to its alternatives and for setting the value of distributed generation technologies.

7.2.5.4 Example

Value assessment of residential solar photovoltaics.

7.3 Emerging Metrics

Emerging metrics address electricity affordability from the perspective of the *cost burden* faced by customers. Cost-burden measures the proportion of income or revenue required to acquire the desired level of electricity service. Customer cost burden is compared to some expected normal or expected burden for a specific geographic area of interest (service territory, state, balancing area, intercon nect, etc.). The metrics discussed derive from cost burden. They are much less widely adopted than the long-established and widely understood metrics discussed above, which deal with cost-effectiveness, rather than cost burden.

The DOE multi-year program plan for grid modernization (DOE 2015a) established the basis for developing these emerging metrics in addition to cost-effectiveness metrics. In the grid modernization context, affordable electricity "maintains reasonable costs to consumers." The program plan also recommends developing capabilities to "rapidly evaluate new business models and impacts of policy decisions working with states." This guidance is consistent with explicitly accounting for the "ability of users to pay" as defined by Taft and Becker-Dippmann (2014).

When discussing cost burden or customer costs within the metrics framework, we are referring to *net* costs. Implicit in the notion of customer costs of electric service are any offsetting tangible benefits accrued, in addition to the electric service provided. For example, consumers with appliances outfitted to provide demand response service to the utility may receive credits on their bills which may partially offset the cost of their electricity use. As grid modernization proceeds, additional consumer benefits are likely to emerge and provide offsets to the cost of electricity for consumers. Customer affordability metrics need to reflect net cost of electricity service, including any credits the customer receives.

7.3.1 Customer Cost Burden

Emerging affordability metrics all derive from the notion of customer cost burden. Actions taken to modernize the grid might include the development and deployment of new technologies, new policies, and the creation of new markets for new products and services. These actions require investments and expenditures by electricity providers. The costs to provide these new products and services must be recouped, which generally occurs by passing them on to customers in the form of electricity rates. The aggregation of a customer's net expenditure on electricity over a year relative to that customer's household income (residential) or gross revenue (commercial and industrial) is the cost burden:

$$\text{Household electricity burden} = \frac{\text{Annual residence net electricity bill}}{\text{Annual household income}}$$

$$\text{Business electricity burden} = \frac{\text{Annual enterpise net electricity bill}}{\text{Annual gross revenue}}$$

Customer net expenditures account for subsidies, rebates, and discounts received to reflect the actual out-of-pocket expenditure for electricity. For residential customers, household income is used for convenience, consistency, and availability, but any income metric (e.g., family income, disposable income) can be used as long as it is applied consistently and compared with like metrics. However, for general comparability to other studies, household income is generally preferred. For commercial and industrial customers (businesses), annual gross revenue is used to provide a generally consistent income metric.

Most of the affordability literature focuses on *energy* affordability (all fuels), as opposed to electricity-only affordability. In this Reference Document, we cover *electricity* affordability only and adapt the cost-burden metrics developed in the wider literature for electricity-specific use. In addition, this Reference Document focuses only on the residential sector. The development of meaningful cost-burden metrics for the commercial and industrial sectors may proceed in the future.

7.3.1.1 Affordable Cost Burden

The concept of what cost burden is "affordable" is the subject of considerable literature. Existing applications of this metric suggest that residential *energy* bills (including electricity and heating fuel) are affordable if they are no greater than 6 percent of household income (Colton 2011). This threshold is derived by logical deduction, rather than by quantitative analysis, but has been deemed reasonable by many practitioners. The notion Colton (2011) reviews is that many studies have identified that total housing costs should not exceed 30 percent of household income to be affordable, and this is now universally accepted, as evidenced by wide adoption in the mortgage finance industry. Further, utility costs should not exceed 20 percent of total housing costs to be affordable. Therefore, 20 percent of 30 percent equals the 6 percent figure deemed to be the affordable burden for household utility costs (Colton 2011). Electricity is not explicitly broken out in this construct, but to estimate the affordable electricity cost burden, the electricity fraction of all utility expenditures is needed. Thus, if electricity costs represent half of the energy costs of the household, the affordable electricity burden would be 3 percent.

Other practitioners use other approaches for determining the affordable cost burden threshold. The American Council for an Energy-Efficient Economy (ACEEE) examined metropolitan area Census data using the American Housing Survey and the American Community Survey (ACS) (Drehobl and Ross 2016), and found median income households had a median energy burden of 3.5 percent, while the median low-income burden was 7.2 percent, and higher income households had a median energy burden of 2.3 percent. Drehobl and Ross (2016) identify several possible cut-off points for what defines affordable:

- Six percent, derived originally from Colton (2011), which is based on the 30 percent of income cap for housing costs and 20 percent of shelter costs for energy.
- The Applied Public Policy Research Institute for Study and Evaluation models severe shelter burden as 50 percent of income and energy costs as about 22 percent of shelter costs, or 11 percent of income.
- The Nevada threshold is that low-income home energy burdens should be no higher than the median.
- Others point to a level no more than twice the median.

For ACEEE's purposes, Drehobl and Ross settled on the median burden metric for their examination of metropolitan area energy affordability for low-income customers (Drehobl and Ross 2016). This metric suggests that the affordable energy burden would be no higher than the median energy burden for the geography being analyzed.

European researchers suggest other alternative energy affordability threshold metrics (Heindl and Schuessler 2015):

- The Ten Percent Rule defines a household as fuel poor if it uses 10 percent or more of disposable income for energy services (used in the United Kingdom since 1991).
- Low-Income/High Cost is when expenditures on all energy services are above the median expenditure and the household falls below the official income poverty line *after* expenditure on all energy services.
- Twice the median burden defines a household as energy poor if their total energy expenditure is 2 times the median of the overall population. This metric offers a couple of advantages in that it is not a static value and it is not specifically linked to low income, although in practice it likely is.

For the purposes of evaluating GMLC outcomes, a broadly applicable standard threshold is attractive. Based on the evolution of the general housing cost affordability threshold of 30 percent, experience has shown that metric to have gained practically universal acceptance as a guiding criterion in mortgage finance, low-income housing assistance, and other forms of household financial assistance programs and policies. It would not seem unreasonable to derive a residential electricity affordability threshold standard from the housing cost affordability threshold standard.

Such a standard does not explicitly require the identification of low-income households, but applies generally to all households. However, as will be discussed, derivative headcount metrics necessarily require stratification of households by income classes. Using a flat percentage threshold provides a simple demonstration of the application of the affordability metrics. It also allows for analytical flexibility because metrics can be estimated for various threshold values to illustrate threshold sensitivity. The metrics examined for GMLC purposes were estimated using alternative fixed-percentage threshold values.

7.3.2 Electricity Affordability Gap

The first metric deriving from the calculation of the household electricity cost burden is the electricity affordability gap. The electricity affordability gap is the ratio of the dollar amount by which electricity bills in a specified geographic region vary from what electricity bills would be if they were set equal to an affordable percentage of income. This factor is simply the ratio of the household electricity burden to the affordable threshold burden deemed to apply to that household:

:

$$\text{Household electricity affordability gap} = \frac{\text{Household electricity cost burden}}{\text{Affordable cost burden threshold}}$$

This metric gives an indication of how much actual electricity costs vary from the threshold burden deemed to be affordable. For example, if the affordable electricity burden deemed to apply to a service territory is 4 percent and the customer cost burden is 6 percent, the gap is calculated as follows:

$$\frac{6\%}{4\%} = 1.5,$$

indicating that customers incurred net electricity costs that were 1.5 times greater than what would have been affordable. This metric provides insights into the *current* state of electricity affordability.

7.3.3 Electricity Affordability Gap Index

The affordability gap index simply tracks the electricity affordability gap ratio for a specific geography through time (t+y (y = years)), relative to a base year:

$$\text{Household electricity affordability gap index} = \frac{\text{Affordability gap}_{(t+y)}}{\text{Affordability gap}_{(t)}}$$

For example, if the affordability gap metric is 1.5 in the base year and increases to 1.8 in the analysis year, the affordability gap index is calculated as follows:

$$\frac{1.8}{1.5} = 1.2,$$

indicating that the affordability gap has widened by a factor of 1.2 over the analysis period. This metric provides insights into the *trend* in electricity affordability.

7.3.4 Electricity Affordability Headcount

A headcount metric equates the electricity burden and related affordability gap to the number of affected households. The number or percentage of households facing unaffordable electricity costs is estimated based on the household electricity burden explained above for specific geographic coverages. For the case where customer billing data have been matched with customer household income data, the headcount is simply the summation of the households that have an electricity affordability gap greater than 1.

In cases where public data are necessary to estimate the electricity affordability gap, the analysis is more complex and requires the use of Census ACS data on household income to do the estimation. The ACS data are used to derive income bins for the households in the affected geography. Specifically, using the Census web form interface, the analyst acquires, for the subject geography, the ACS 5-year data for Table B19001 (Census 2016) on household income, which bins the number of households into 16 discrete annual income bins. This provides the highest income resolution possible for calculating average burdens using public data.

Next, for each income bin, the midpoint income is calculated. This will be the value used for the income portion of the burden calculation. For the endpoints of the income distribution, judgment is required. For simplicity, it may be acceptable to use the bounding values of the end-point bins (e.g., the maximum value of the lowest bin and the minimum value of the highest bin). This will slightly distort the end-point burden calculations. However, under common affordability threshold burden values, it would be expected that the lowest bin would always be found to face an unaffordable cost burden and the highest bin would never be found to face an unaffordable cost burden.

Next, each income bin's share of households is calculated by dividing each bin's number of households by the total number of households. The cost burden by income bin is calculated by dividing the estimated average customer cost for the area of interest by each income bin midpoint income. This yields 16 individual customer cost-burden values, one for each segment of the household income distribution. Taking the weighted average of the 16 values yields the area average customer cost burden. Using the midpoint of each bin implicitly assumes that the number of households in each income bin is normally or uniformly distributed within the income bin such that the midpoint income would represent the average of the bin.

With the cost burden by income bin calculated, the number of households facing unaffordable electricity cost burdens can be estimated by varying the threshold percentage deemed to be affordable. This is done by summing the bins of all cost burdens greater than the threshold value. This value is reported as the percentage of all households in the analysis area facing unaffordable electricity net costs.

7.3.5 Electricity Affordability Headcount Index

The affordability headcount is calculated for a series of years. The index simply tracks this value for a specific geography through time (t+y (y = years)), relative to a base year:

$$\text{Household electricity affordability headcount index} = \frac{\%\ \text{Unaffordable}_{(t+y)}}{\%\ \text{Unaffordable}_{(t)}}$$

For example, given our example territory, the number of households estimated to have electricity costs higher than the established affordable threshold is 10,000 of 100,000 (10 percent) in the base or reference year. In the analysis year, this number is estimated to be 15,000 of 120,000 (12.5 percent). The headcount index would be calculated as follows:

$$\frac{12.5\%}{10.0\%} = 1.25,$$

suggesting that the number of households facing unaffordable electricity costs rose 25 % between the base year and the analysis year.

7.3.6 Average Customer Electricity Cost

Stakeholder input suggests that average electricity costs (effective rates) by customer class would provide an additional meaningful affordability metric. As rates change, electricity costs and related cost burdens also change. Grid modernization activities that result in rate changes ultimately can be linked to changes in customer affordability.

Average rates alone are not a satisfactory indicator of whether or not the cost of electricity is affordable. There must be some comparison to average usage of electricity to estimate actual affordability. For example, most of the southern states had average residential rates lower than the national average, but also had total annual electricity costs that were much higher than the national average. This suggests that electricity is the principal fuel used in these states and usage was much higher than the national average.

The annual average customer cost or effective rate ($/kWh) for a given geographic coverage *i* and customer class *c* is indicated by the following simple equation:

$$\text{Annual Average Customer Cost}_{(i,c)} = \frac{\text{Total Revenue}_{(i,c)}}{\text{Total Consumption}_{(i,c)}}$$

7.3.7 Average Customer Electricity Cost Index

Tracking this effective rate through time results in an index for making relative comparisons between time periods:

$$\text{Average Customer Cost Index} = \frac{\text{Avg Customer Cost}_{(t+y)}}{\text{Avg Customer Cost}_{(t)}}$$

7.3.8 Maturity Level

These measures are generally understood and are reflected in the literature for the residential sector. In addition, forms of cost-burden metrics are used for determining eligibility for participation in utility or government low-income programs such as weatherization assistance, bill assistance, etc. Very little has been done to analyze commercial and industrial customer affordability using the cost-burden metric approach. Compared to the cost-effectiveness metrics discussed in Section 7.2, the maturity of these metrics is low. There are applications in the literature, but industry-standard approaches for their use, especially for assessing the impacts of grid modernization, have yet to be developed.

7.3.9 Applications

The existing metrics described in Section 7.2 are used widely within the context of grid investments and are generally understood to be industry-standard approaches for measuring costs and benefits. Voluminous literature exists that both derives and documents the theory and application of cost-effectiveness metrics. National assessments, state PUC regulatory processes, and firm-level investment decisions all rely on the established cost-effectiveness metrics.

The emerging cost-burden metrics are of value primarily to electricity regulators such as PUCs or state agencies charged with caring for the interests of electricity customers. Having a consistent methodology for examining potential changes in the affordability of electric service induced by future grid modernization and the development of new products and services provides a customer-side check on the impacts of modernization. Beyond grid modernization, reliable and consistent affordability metrics can provide quantitative standardization for how cost equity concerns are analyzed.

7.3.10 Data Source and Availability

As with all metrics, affordability metrics are only as valuable as the quality of the data used to derive them. Fundamentally, two data sources are required to estimate electricity cost burden: household electricity cost and household income. Ideally, the most robust estimation of cost burden would be made using individual customer annual billing data (net bill) and individual customer annual household income. While electricity utilities would have the billing data for their customers, they may or may not also have customer household income data. Entities other than the electricity service provider are not likely to have customer billing data or customer income data. The methodology described details how metrics can be estimated with or without access to these key data sets. Public data sources are used to demonstrate the application with the understanding that the availability of specific customer-level data would be the preferred case for deriving the most meaning from the metrics.

The firm Fisher, Sheehan, and Colton (2013) has expanded on the notion of the 6 percent affordability threshold and now provides a public, nationwide, data set on home *energy* affordability derived from using county-level household income and a proprietary model for estimating annual average customer electricity bills using the Residential Energy Consumption Survey (RECS) microdata, ACS data, and public weather data on heating and cooling degree-days by region. The firm publishes the data annually for each state and its counties, segmented by income bins.

In the absence of utility-supplied customer billing data, there are public sources of summarized residential billing data. The EIA provides annual summarization of electricity sales and revenue by customer class for all utilities in the country that file Form 861 (EIA 2016a). Service territory annual average electricity bills can be simply calculated by dividing reported residential electricity sales revenue by the number of customers reported. This provides a relatively geographically refined estimate of household electricity cost, but sacrifices the potential refinement that may be possible using the RECS microdata to account for household size, weather, and other factors. However, using the EIA Form 861 data requires much less analysis time than performing econometric analysis of the RECS data. The use-case discussion will examine these tradeoffs. For the purposes of summarizing average customer costs per kilowatt-hour, the Form 861 data, adjusted for inflation, would be sufficient to generate average rate estimates at the national, state, and service area geographic levels.

7.3.11 Challenges

Research is needed to develop an approach for constructing such metrics for nonresidential customer classes. In addition, these metrics would be used by entities that can hypothesize the impact of cost and benefit allocations on customer classes (e.g., rate making). Research is needed to understand the trade-off between analytical convenience and accuracy of metric calculations.

7.3.11.1 Commercial and Industrial Sector Metrics

Little if any research has been done to estimate empirically what constitutes affordable electricity to businesses. Unlike the residential sector, there is no convergence around a threshold gross revenue percentage deemed to indicate an affordability bound. While residences are somewhat homogeneous, businesses vary widely in their use of electricity relative to their gross revenues. Electricity-intensive industries necessarily spend higher proportions of their input budgets on electricity, while for other businesses, electricity use can be minor, relative to all other production inputs.

7.3.11.2 Affordability Impact Assessment

Performing impact analysis using these emerging metrics will depend upon reliable assignment of costs and benefits to rates, exogenous to the impact analysis. The emerging metrics discussed in this section provide lagging measures of general electricity affordability. The next step is to link the metrics to the output of cost allocation analysis. To estimate the affordability impacts of future grid modernization will require the translation of expected activities into costs and benefits, then allocation of costs and benefits to annual customer costs. This can require complex modeling, depending on the actions hypothesized. For example, new service pricing may induce offsetting behavior among customers. It will be increasingly important to reliably allocate the benefits of customer actions under a modernized grid as credits against annual net electricity costs (net bill).

7.3.11.3 Use of Average Annual Bill Data

As discussed, in the absence of utility customer- or residence-specific billing data for the numerator of the cost-burden metric, average household bills can be estimated from public data sources. At least two concerns should be further studied. First, those having lower household income would be expected to have received higher proportions of subsidies. For example, most utilities have some form of low-income utility assistance and/or "lifeline" type of service for the lowest income customers. This noticeably reduces the cost burden faced by these customers—making the use of a class or geographic average less representative or misleading. The Alaska use-case discussed in Section 7.5 is valuable because the customer cost data provided explicitly netted out the effect of customer subsidies. Second, the use of average annual net bills implies that a "top-down" average cost burden would not differ significantly, in aggregate, from a cost burden carefully derived from data on household size, electricity proportion of fuels used, heating and cooling degree-days, electric load profiles, floor space, or other explanatory variables. A useful test would be to estimate and compare the affordability metrics using alternative formulations of the net electricity cost derived from public data sources including RECS, EIA Form 861, or available state-level data sources.

Examining customer affordability using annual average bills can mask acute affordability challenges that could be revealed using monthly billing data. Some households, which would appear to face affordable electricity when costs are figured on an annual basis, may face bills that exceed affordability thresholds during certain months of high heating or cooling demand. Accounting for this potential would add customers to the headcount metrics and require that billing data partners supply monthly data. EIA data from Form-826 (EIA 2017c) could provide a useful test for identifying the impact of examining monthly versus annual customer cost data.

7.4 Scope of Applicability

Established and emerging affordability metrics have meaning and applicability at any level of desired spatial or grid-hierarchical aggregation. From DOE's perspective, the value of examining the affordability of grid modernization is that the emerging metrics can be examined at all aggregation levels, using uniform calculation methods. Thus, the outcomes of grid modernization investments can be measured in consistent affordability terms at a national, state, congressional district, county, local, or utility-system level.

Established and emerging affordability metrics are useful at the system level from the perspective of internal service-provider decision-making. Cost-effectiveness metrics are used as a matter of standard practice to evaluate investment decisions regarding new power plants, new efficiency technology deployments, new transmission and distribution equipment upgrades, or distributed generation deployment. Cost-burden metrics will become increasingly important at the system level in the future. As the grid becomes more transactive and customers gain access to services that enable them to customize their participation in electricity markets, the metrics will have greater meaning at smaller geographic and temporal scales.

7.4.1 Utility Level

Established and emerging affordability metrics gain wider usefulness at the utility level. Regulated utilities rely upon cost-effectiveness metrics to build their case to their regulators for cost-of-service recovery from their rate base. Decisions regarding construction of new power plants, new efficiency technology deployments, transmission and distribution equipment upgrades, or distributed generation deployment become subject to robust and public estimates of cost-effectiveness metrics that are reviewed and vetted by regulators, investors, the public, and shareholders. Merchant generator also rely upon traditional cost-effectiveness metrics to make investment decisions regarding potential markets for their power.

Customer cost-burden metrics are gaining in importance to individual utilities from the social responsibility perspective. As grid modernization activities proceed, utilities will increasingly want to be perceived favorably among their peers, to their regulators and customers. As the grid becomes more transactive, customers will increasingly be able to choose their electricity supplier. Affordability metrics derived from customer cost burden may become a differentiator for service providers, in the context of socially responsible electricity delivery. Merchant power providers typically are focused on the provision of wholesale power and would only be concerned with cost-burden metrics to the degree that power retailers pass those concerns on explicitly to wholesale providers.

As shown in Figure 7.1, customer affordability metrics can be illustrated in great detail within a utility service area. In this case, the Sacramento Municipal Utility District (SMUD) also aligns with the boundaries of Sacramento County. Census block groups were mapped and shaded according to the proportion of households facing unaffordable electricity at the 3 percent cost threshold. The block groups are binned into five ranges of percentages of households having cost burdens greater than 3 percent.

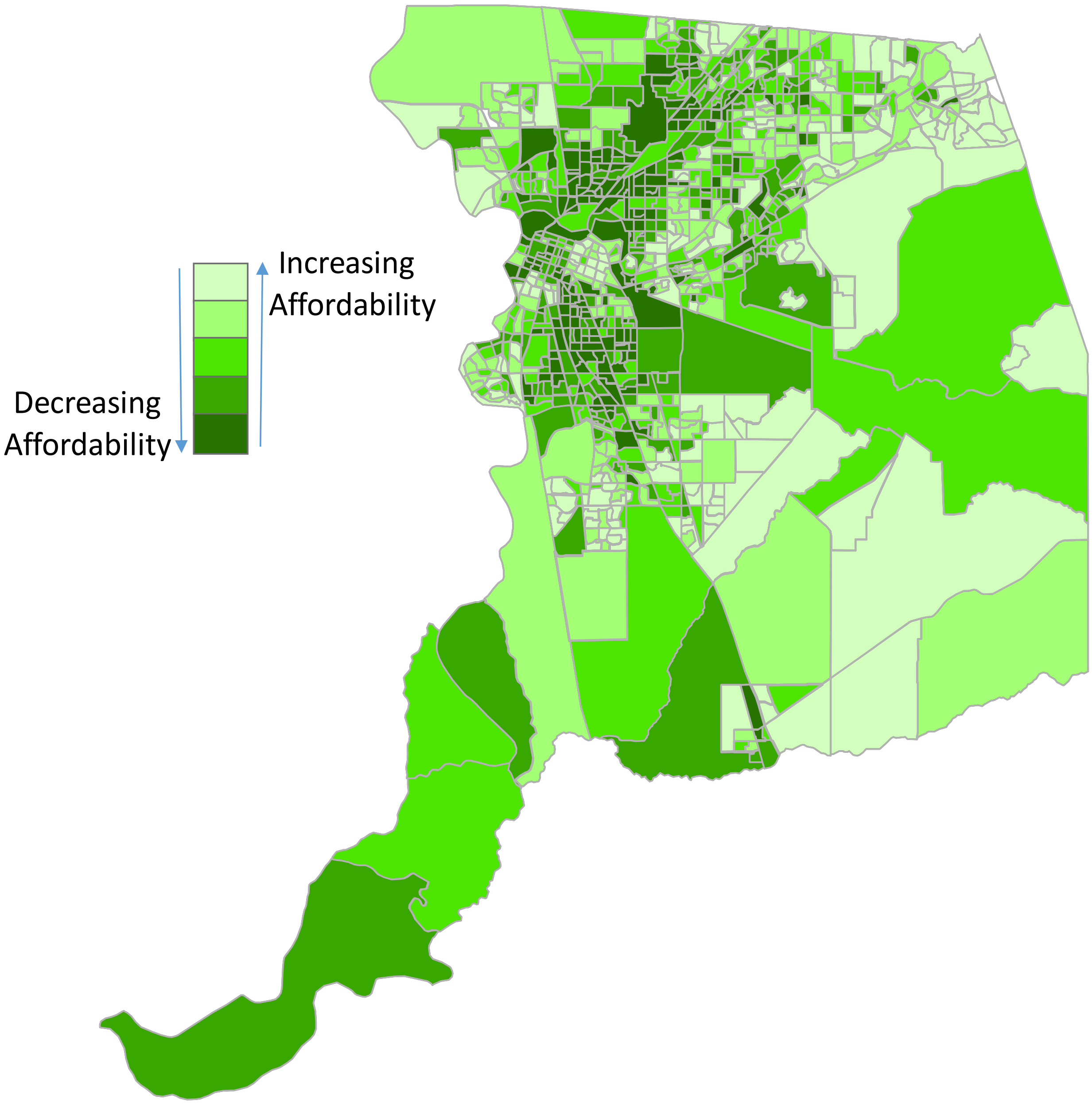

Figure 7.1. 2015 residential customer affordability (3 percent threshold) by Census block group in the Sacramento Municipal Utility District.

Two observations from the figure can be made. First, customer affordability varies considerably across spatial extents even within a single county. Electricity is less affordable in low-income areas around the City of Sacramento, but also in some more rural areas of the county. Suburban areas, where average incomes would be expected to be generally higher, appear to have fewer households with cost burdens greater than the affordable threshold value. Second, even in a geographically small utility service area like SMUD, affordability varies considerably across the territory.

7.4.2 State Level

Established and emerging affordability metrics also have importance at the state level. Most regulated utilities are subject to state regulation. PUCs are generally charged with ensuring that the actions of electricity utilities are fair and equitable toward customers (residents and businesses of the state). Utilities must demonstrate that the costs for which they request recovery from rate payers are fair and equitable. Cost-effectiveness metrics are used as a matter of standard practice to demonstrate the practicality or reasonableness of requested investments.

For the purposes of states and other political jurisdictions, cost-burden metrics are useful in providing an assessment of the equity of proposed rate changes proposed by utilities. Customer advocacy groups could benefit from the availability of uniform affordability metrics applicable at any geographic scale of interest. Adoption of uniform cost-burden metrics would enable utility commissions to consider more formally customer affordability in their deliberations.

Figure 7.2 uses microdata from the most recent RECS (EIA 2013) to illustrate the average customer cost burden across the state groupings used in the RECS. Two observations are possible. The average cost burdens by state are somewhat higher in the South than in other parts of the country, though generally residential electricity rates are lower in that region. This illustrates the effect of average household incomes on the cost-burden metric. Average incomes are generally lower in the southern states than, for example, in the northeastern states. This results in the electricity cost burden being higher. The higher incomes in the northeastern states mitigate the higher electricity costs those customers face, making their cost burden lower.

Figure 7.3 examines the RECS consumer cost and income data in terms of the affordability headcount. Setting the affordable cost burden at 5 percent, the number of households that have cost burdens greater than that threshold value were charted to illustrate the difference among the state groupings used in the RECS. The values range from 7 percent of households in Colorado to over 40 percent in Florida, Georgia, North Carolina, and South Carolina, based on the 2009 RECS microdata. The U.S. average for the 5 percent threshold is 27.5 percent of households having cost burdens greater than the threshold value.

As noted in Section 7.3.1.1, these metrics rely upon the selection of a threshold value. Alternative threshold values yield different results by definition. The higher the affordable threshold is set, the higher the number of residential customers that will be estimated to have affordable electricity. The lower the threshold, the higher the number of residential customers that will have unaffordable electricity cost burdens.

The affordability headcount can be illustrated for any level of spatial aggregation (state, county, Census block groups, utility service areas, etc.), as demonstrated above for SMUD in California and below at the county level for the counties in California in Figure 7.4. In this figure, the variation in affordability within the state is evident. Cost burdens were estimated at the utility service area level using the EIA Form 861 data discussed in Section 7.3.8 and the Census ACS data on household income. Observations similar to those derived from the use of the RECS data can be made. Areas with generally higher incomes have fewer households with cost burdens above the affordable threshold (3 percent used in this case). However, counties outside the large investor-owned territories also have higher average electricity costs. These two factors together suggest the most affordable electricity in California is in the Bay Area counties and central and southern coastal counties.

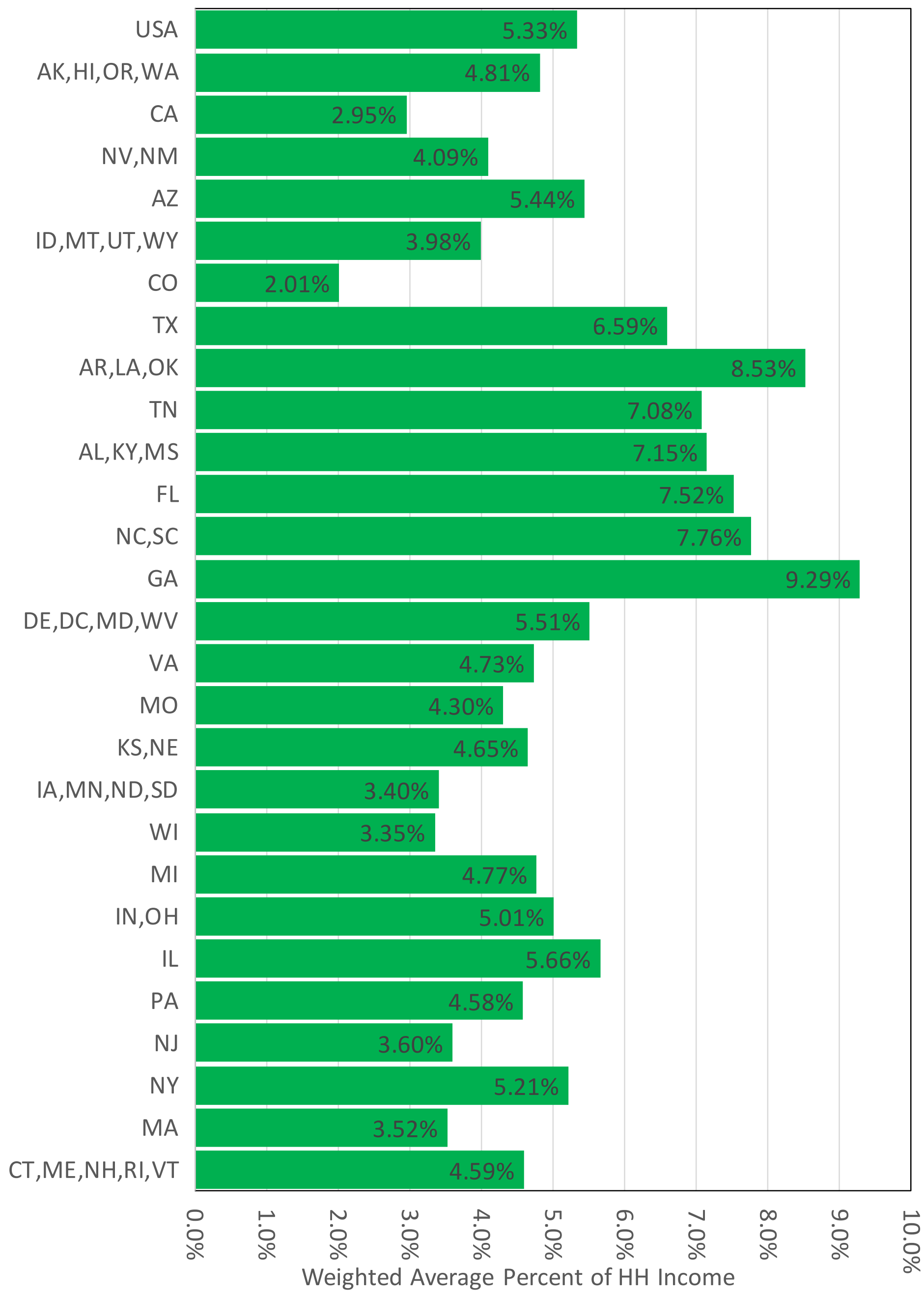

Figure 7.2. 2009 average residential customer electricity cost burden (EIA 2013).

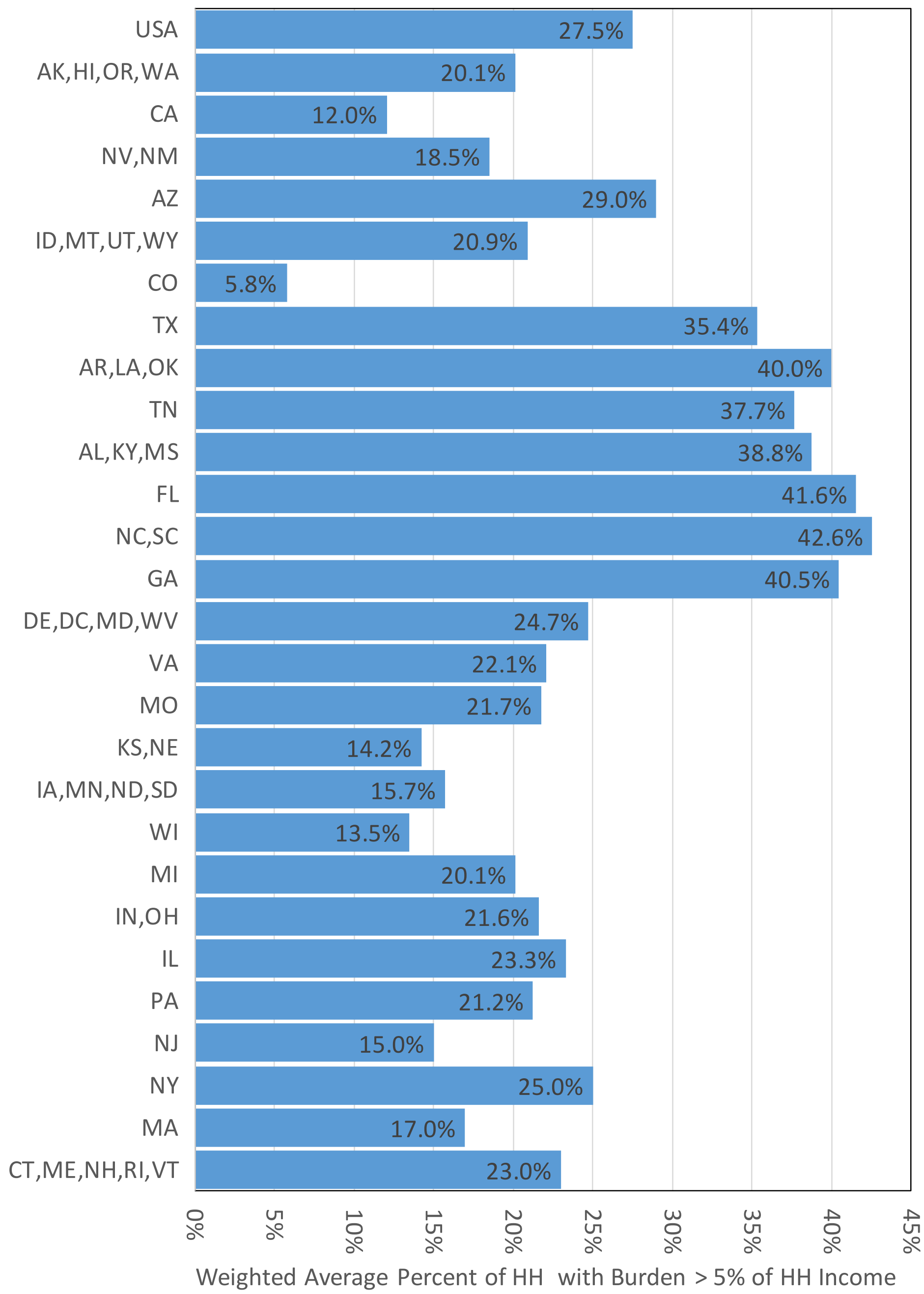

Figure 7.3. 2009 average percentage of households with electricity cost burdens greater than 5 percent of household income (EIA 2013).

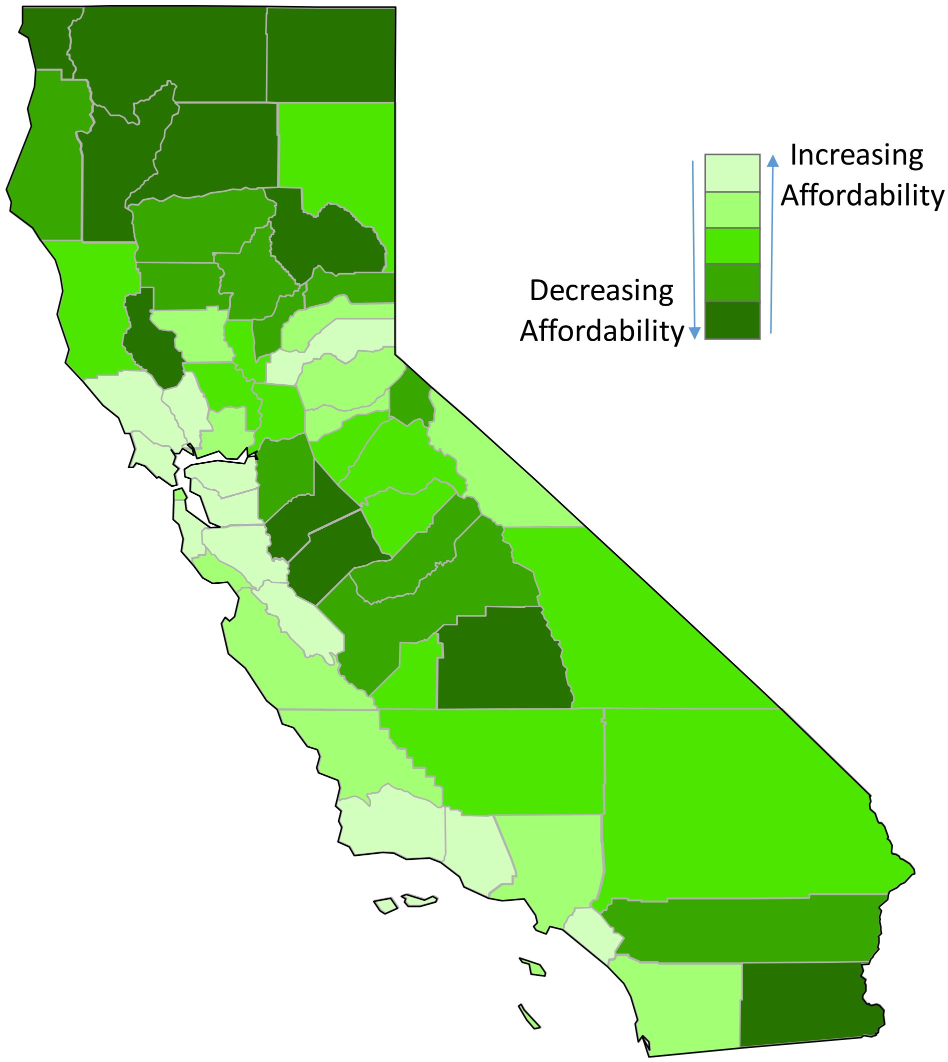

Figure 7.4. 2015 California county-level residential customer affordability at the 3 percent cost-burden threshold.

Figure 7.5–Figure 7.7 illustrate the difference between simply examining average rates by customer class and consideration of electricity usage to estimate annual electricity cost (and the related downstream metrics associated with cost burden). These figures are derived using EIA Form 861 electricity sales data by utility and state (EIA 2016a).

The movement of average rates over time may suggest whether electricity is becoming more or less affordable. For the same usage levels, rising average rates would indicate declining affordability of electricity, and declining average rates would indicate increasing electricity affordability. An index provides the means to track this metric over time. Table 7.1–Table 7.3 report the state and national annual average rate index by customer class, based on 2015 constant-dollar (adjusting for inflation) summarization of kilowatt-hour sales and revenue data reported to EIA (EIA 2016a) over the 2006–2015 period. Average rates reflect the total revenue divided by the total kilowatt-hours sold. Revenues include all billed usage, including demand charges and other applicable fees tied to usage.

As with the other index metrics discussed, numbers greater than 1 indicate that average rates have increased, net of inflation, relative to the base year, while numbers lower than 1 indicate rates have declined. For example, at the national level average rates have been slowly declining in real terms for commercial and industrial customers, relative to 2006 levels, while residential average rates have increased slightly over the same period. State-specific indices show considerable variation by state and customer class. Variation in real average rates is greater among commercial and industrial customers, given the differing mix of industries in different states and differences in classification of businesses into those rate classes. This highlights the difficulty in developing cost-burden metrics for nonresidential customers.

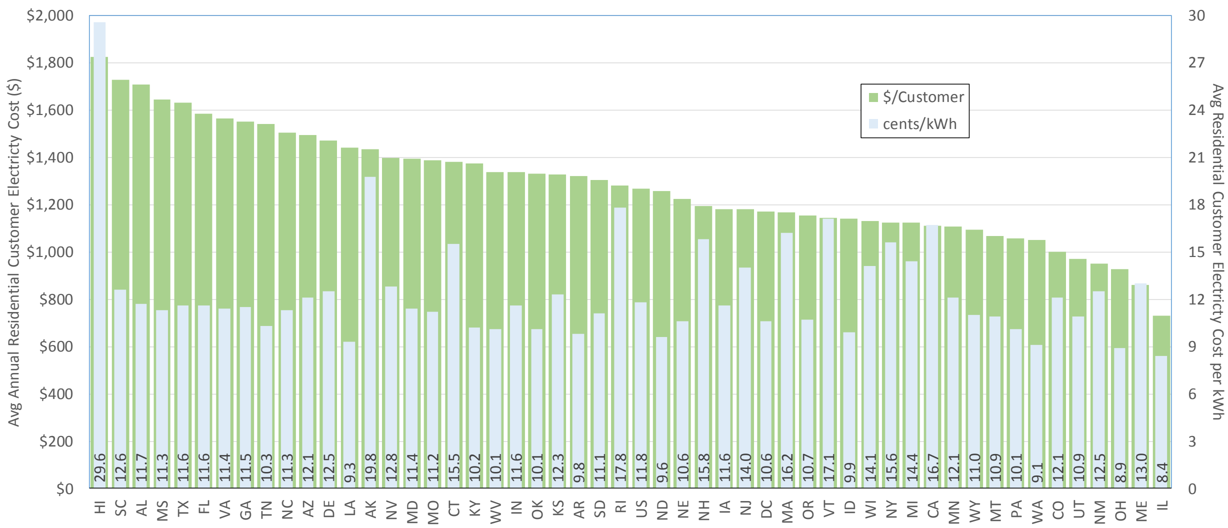

Figure 7.5. 2015 residential sector average electricity cost per customer and rates by state (EIA 2016a).

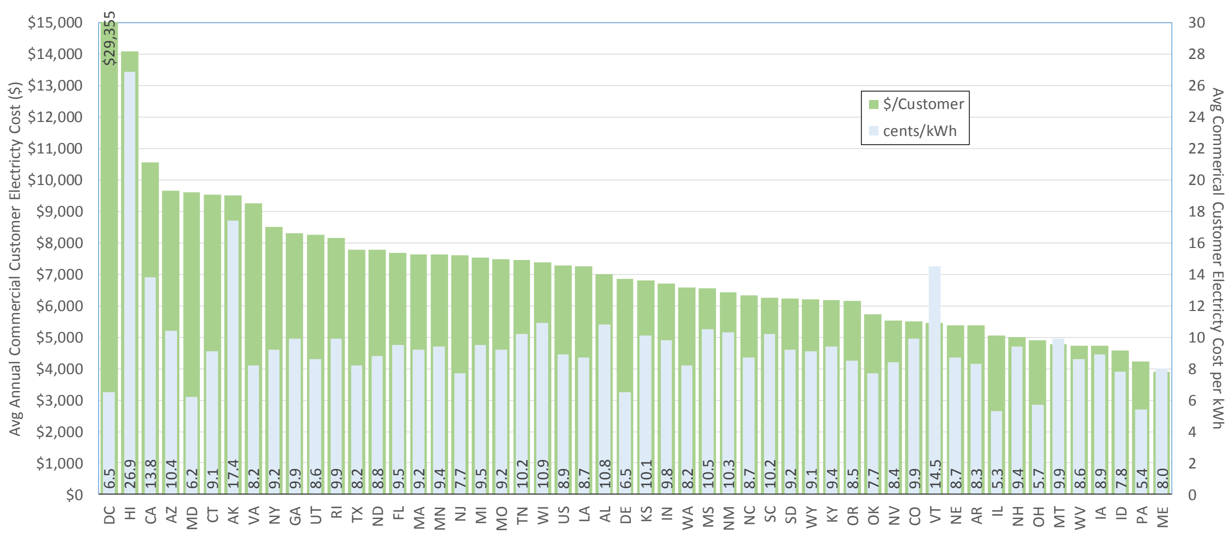

Figure 7.6. 2015 commercial sector average electricity cost per customer and rates by state (EIA 2016a).

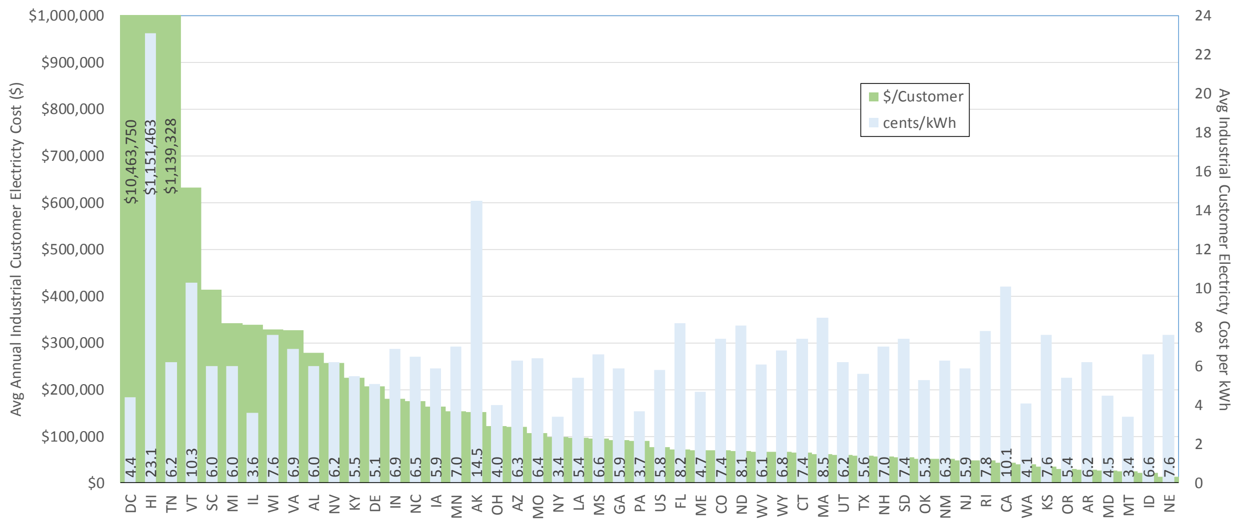

Figure 7.7. 2015 industrial sector average electricity cost per customer and rates by state (EIA 2016a).

Table 7.1. 2006–2015 State and National Average Real Residential Rate Index (2006 = 1).

State	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
AK	1.000	0.998	1.050	1.085	1.018	1.066	1.062	1.058	1.099	1.138
AL	1.000	1.027	1.107	1.142	1.124	1.130	1.137	1.111	1.113	1.131
AR	1.000	0.950	0.978	0.960	0.924	0.906	0.917	0.933	0.909	0.937
AZ	1.000	1.003	1.026	1.069	1.082	1.058	1.055	1.077	1.078	1.095
CA	1.000	0.979	0.904	0.966	0.950	0.921	0.939	0.974	0.959	0.993
CO	1.000	1.004	1.051	1.044	1.130	1.125	1.122	1.144	1.154	1.143
CT	1.000	1.050	1.051	1.049	0.845	0.704	0.646	0.642	0.747	0.809
DC	1.000	1.102	1.216	1.288	1.267	1.155	0.977	0.963	0.966	0.929
DE	1.000	1.071	1.087	1.099	1.065	1.018	0.975	0.909	0.895	0.901
FL	1.000	0.963	0.970	1.031	0.932	0.912	0.886	0.865	0.897	0.873
GA	1.000	0.994	1.042	1.066	1.049	1.118	1.105	1.118	1.110	1.099
HI	1.000	1.005	1.306	0.976	1.115	1.335	1.405	1.374	1.352	1.080
IA	1.000	0.952	0.927	0.979	1.001	0.980	0.988	0.991	0.993	1.028
ID	1.000	1.003	1.057	1.182	1.193	1.142	1.232	1.298	1.332	1.358
IL	1.000	1.169	1.237	1.264	1.265	1.238	1.003	0.711	0.781	0.851
IN	1.000	0.984	1.016	1.088	1.082	1.104	1.124	1.161	1.194	1.203
KS	1.000	0.960	1.004	1.075	1.114	1.144	1.185	1.209	1.252	1.260
KY	1.000	1.014	1.057	1.127	1.136	1.178	1.179	1.211	1.241	1.239
LA	1.000	1.004	1.060	0.836	0.914	0.886	0.810	0.894	0.898	0.869
MA	1.000	0.934	0.967	0.921	0.787	0.769	0.748	0.770	0.824	0.889
MD	1.000	1.175	1.317	1.419	1.280	1.073	0.979	0.964	0.976	1.010
ME	1.000	1.153	1.097	1.060	1.043	0.999	0.928	0.890	0.937	1.580
MI	1.000	1.012	1.022	1.112	1.179	1.216	1.263	1.289	1.260	1.250

Table 7.1. (contd)

State	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
MN	1.000	1.028	1.044	1.080	1.126	1.133	1.150	1.174	1.175	1.183
MO	1.000	1.012	1.012	1.079	1.137	1.175	1.210	1.239	1.220	1.287
MS	1.000	0.942	1.004	0.988	0.943	0.942	0.932	0.963	0.992	0.991
MT	1.000	1.031	1.027	1.007	1.024	1.058	1.068	1.074	1.046	1.117
NC	1.000	1.004	0.978	1.032	1.026	1.014	1.052	1.046	1.039	1.056
ND	1.000	0.999	0.989	1.006	1.054	1.085	1.125	1.109	1.091	1.150
NE	1.000	0.998	1.000	1.079	1.112	1.126	1.186	1.204	1.197	1.218
NH	1.000	0.985	1.000	1.035	1.025	1.006	0.938	0.824	0.852	0.914
NJ	1.000	1.071	1.149	1.196	1.184	1.043	0.940	0.906	0.905	0.930
NM	1.000	0.972	1.029	1.032	1.066	1.083	1.100	1.112	1.151	1.168
NV	1.000	1.033	1.004	1.092	1.033	0.936	0.933	0.928	0.990	0.981
NY	1.000	0.966	0.978	0.921	0.960	0.896	0.828	0.860	0.906	0.845
OH	1.000	1.005	1.021	1.066	0.987	0.906	0.858	0.826	0.823	0.851
OK	1.000	0.984	1.002	0.939	0.989	1.002	0.981	0.987	1.002	1.011
OR	1.000	1.063	1.061	1.090	1.097	1.135	1.147	1.142	1.192	1.213
PA	1.000	1.029	1.019	1.050	1.051	0.975	0.843	0.797	0.801	0.842
RI	1.000	0.901	1.079	0.970	0.967	0.843	0.826	0.848	0.914	1.003
SC	1.000	0.994	1.030	1.086	1.078	1.105	1.151	1.154	1.183	1.191
SD	1.000	1.009	0.996	1.024	1.066	1.080	1.137	1.143	1.146	1.210
TN	1.000	0.972	1.068	1.120	1.090	1.149	1.137	1.109	1.124	1.123
TX	1.000	0.927	0.944	0.903	0.831	0.771	0.749	0.765	0.786	0.765
UT	1.000	1.049	1.023	1.051	1.058	1.061	1.144	1.184	1.188	1.220
VA	1.000	0.995	1.058	1.171	1.131	1.118	1.146	1.099	1.112	1.141
VT	1.000	1.023	1.013	1.045	1.076	1.090	1.114	1.104	1.112	1.085
WA	1.000	1.044	1.033	1.064	1.087	1.094	1.097	1.107	1.089	1.138
WI	1.000	1.009	1.026	1.065	1.109	1.109	1.104	1.112	1.111	1.142
WV	1.000	1.018	1.039	1.160	1.271	1.316	1.358	1.284	1.237	1.342
WY	1.000	0.985	0.997	1.049	1.056	1.059	1.117	1.146	1.161	1.215
U.S.	**1.000**	**1.007**	**1.047**	**1.054**	**1.048**	**1.035**	**1.024**	**1.018**	**1.034**	**1.051**

Table 7.2. 2006–2015 State and National Average Real Commercial Rate Index (2006 = 1).

State	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
AK	1.000	0.997	1.070	1.145	1.080	1.137	1.099	1.134	1.224	1.244
AL	1.000	1.031	1.130	1.157	1.150	1.147	1.135	1.108	1.122	1.120
AR	1.000	0.958	1.017	1.020	0.964	0.960	0.966	0.989	0.973	1.008
AZ	1.000	1.009	1.042	1.104	1.098	1.064	1.043	1.060	1.075	1.106
CA	1.000	0.972	0.921	0.979	0.948	0.896	0.893	0.924	0.996	0.995
CO	1.000	0.985	1.074	1.027	1.121	1.123	1.100	1.142	1.147	1.123
CT	1.000	0.811	0.767	0.713	0.653	0.586	0.541	0.540	0.583	0.582
DC	1.000	0.906	0.949	0.927	0.912	0.836	0.759	0.748	0.759	0.747
DE	1.000	0.900	0.959	0.905	0.810	0.741	0.683	0.673	0.683	0.683
FL	1.000	0.952	0.955	1.025	0.915	0.887	0.860	0.822	0.852	0.816
GA	1.000	1.009	1.092	1.072	1.078	1.137	1.081	1.109	1.135	1.079
HI	1.000	0.995	1.300	0.961	1.119	1.357	1.432	1.379	1.361	1.069
IA	1.000	0.945	0.924	0.978	1.000	0.970	0.962	0.996	1.015	1.037
ID	1.000	0.953	1.026	1.174	1.173	1.103	1.165	1.231	1.277	1.276
IL	1.000	0.926	0.922	0.895	0.836	0.768	0.669	0.659	0.743	0.716
IN	1.000	0.986	1.014	1.083	1.078	1.095	1.110	1.154	1.183	1.158
KS	1.000	0.944	0.990	1.060	1.083	1.127	1.154	1.199	1.229	1.227
KY	1.000	1.033	1.068	1.116	1.141	1.190	1.193	1.163	1.251	1.249
LA	1.000	0.983	1.051	0.804	0.873	0.836	0.761	0.865	0.861	0.822
MA	1.000	0.914	0.918	0.921	0.860	0.816	0.765	0.780	0.750	0.775
MD	1.000	0.972	1.031	0.967	0.911	0.844	0.763	0.765	0.790	0.764
ME	1.000	1.019	0.982	0.955	0.939	0.896	0.821	0.823	0.879	1.097
MI	1.000	1.034	1.043	1.035	1.030	1.055	1.089	1.095	1.056	1.023
MN	1.000	1.042	1.057	1.060	1.109	1.101	1.104	1.162	1.204	1.142
MO	1.000	1.004	1.013	1.078	1.136	1.175	1.180	1.248	1.242	1.283
MS	1.000	0.920	0.996	0.949	0.914	0.906	0.869	0.930	0.978	0.950
MT	1.000	1.025	1.050	1.016	1.037	1.066	1.056	1.087	1.082	1.138
NC	1.000	0.999	0.988	1.044	1.053	1.008	1.061	1.058	1.041	1.028
ND	1.000	1.018	1.011	1.014	1.056	1.081	1.115	1.154	1.189	1.188
NE	1.000	1.003	1.012	1.106	1.133	1.156	1.189	1.200	1.195	1.193
NH	1.000	0.948	1.005	0.932	0.780	0.712	0.626	0.603	0.635	0.655
NJ	1.000	1.044	1.104	0.989	0.876	0.773	0.702	0.683	0.699	0.689
NM	1.000	0.985	1.072	1.038	1.046	1.073	1.074	1.104	1.154	1.153
NV	1.000	0.972	0.936	0.986	0.869	0.781	0.739	0.711	0.725	0.707
NY	1.000	0.962	0.983	0.902	0.933	0.861	0.791	0.797	0.818	0.775
OH	1.000	0.998	1.035	1.100	0.851	0.731	0.658	0.603	0.627	0.638
OK	1.000	0.972	1.013	0.875	0.937	0.933	0.878	0.925	0.945	0.897
OR	1.000	1.032	1.008	1.055	1.052	1.089	1.081	1.105	1.100	1.112
PA	1.000	0.996	0.971	0.986	0.856	0.664	0.585	0.555	0.578	0.567

Table 7.2. (contd)

State	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
RI	1.000	0.895	1.060	0.816	0.722	0.652	0.601	0.653	0.739	0.739
SC	1.000	0.985	1.035	1.075	1.082	1.097	1.109	1.127	1.154	1.141
SD	1.000	0.987	1.008	1.026	1.081	1.075	1.094	1.131	1.166	1.204
TN	1.000	0.984	1.077	1.127	1.121	1.154	1.130	1.082	1.107	1.084
TX	1.000	0.972	1.012	0.920	0.859	0.797	0.727	0.699	0.705	0.704
UT	1.000	1.036	1.028	1.078	1.076	1.087	1.166	1.177	1.187	1.199
VA	1.000	1.003	1.103	1.227	1.148	1.156	1.147	1.116	1.112	1.125
VT	1.000	1.022	1.000	1.036	1.059	1.072	1.073	1.087	1.063	1.054
WA	1.000	0.972	0.965	0.996	1.036	1.018	1.024	1.023	1.032	1.057
WI	1.000	1.007	1.037	1.074	1.100	1.109	1.097	1.102	1.095	1.104
WV	1.000	1.007	1.020	1.141	1.271	1.296	1.317	1.267	1.216	1.306
WY	1.000	0.957	0.996	1.088	1.086	1.095	1.143	1.181	1.203	1.229
U.S.	**1.000**	**0.976**	**1.021**	**1.002**	**0.987**	**0.977**	**0.958**	**0.966**	**0.986**	**0.972**

Table 7.3. 2006–2015 State and National Average Real Industrial Rate Index (2006 = 1).

State	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
AK	1.000	1.065	1.156	1.070	1.133	1.223	1.283	1.189	1.163	1.072
AL	1.000	1.051	1.166	1.150	1.132	1.134	1.111	1.042	1.077	1.041
AR	1.000	0.972	1.062	1.048	0.960	0.965	0.979	0.998	0.983	1.014
AZ	1.000	1.023	1.084	1.104	1.070	1.038	1.001	1.017	0.971	0.940
CA	1.000	0.984	0.958	1.006	0.924	0.907	0.909	0.987	1.032	1.011
CO	1.000	0.989	1.063	1.019	1.081	1.078	1.027	1.071	1.082	1.067
CT	1.000	0.733	0.758	0.752	0.697	0.619	0.575	0.574	0.588	0.572
DC	1.000	0.900	0.919	0.731	0.668	0.564	0.439	0.449	0.662	0.693
DE	1.000	1.028	1.152	1.066	1.102	0.982	0.861	0.832	0.852	0.834
FL	1.000	0.985	0.997	1.135	1.068	1.001	0.912	0.854	0.874	0.906
GA	1.000	0.990	1.162	1.061	1.061	1.095	0.975	1.009	1.041	0.929
HI	1.000	0.994	1.353	0.945	1.125	1.414	1.502	1.437	1.429	1.091
IA	1.000	0.932	0.917	1.016	1.019	0.951	0.950	0.989	0.991	1.024
ID	1.000	1.053	1.170	1.357	1.309	1.270	1.341	1.466	1.514	1.559
IL	1.000	0.972	1.014	0.965	0.950	0.871	0.756	0.769	0.875	0.851
IN	1.000	0.972	1.051	1.112	1.113	1.134	1.129	1.183	1.216	1.198
KS	1.000	0.953	1.026	1.102	1.102	1.155	1.199	1.231	1.277	1.243
KY	1.000	1.094	1.124	1.151	1.178	1.187	1.185	1.233	1.213	1.169
LA	1.000	0.958	1.072	0.722	0.777	0.740	0.611	0.740	0.740	0.666
MA	1.000	0.972	1.027	0.917	0.880	0.831	0.772	0.792	0.831	0.871
MD	1.000	1.078	1.140	1.103	1.045	0.916	0.840	0.846	0.907	0.832

Table 7.3. (contd)

State	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
ME	1.000	1.409	1.108	0.959	0.868	0.823	0.717	0.742	0.782	0.816
MI	1.000	1.042	1.087	1.107	1.007	1.008	1.035	1.004	0.958	0.911
MN	1.000	1.045	1.042	1.117	1.099	1.099	1.077	1.143	1.076	1.123
MO	1.000	1.014	0.997	1.103	1.105	1.130	1.126	1.185	1.185	1.183
MS	1.000	0.956	1.047	1.051	0.987	0.987	0.923	0.924	0.953	0.951
MT	1.000	1.160	1.238	1.030	1.044	0.925	0.906	0.949	0.961	0.933
NC	1.000	1.028	0.990	1.084	1.102	1.034	1.081	1.065	1.064	1.063
ND	1.000	1.011	1.049	0.977	1.072	1.111	1.159	1.229	1.294	1.378
NE	1.000	1.014	1.059	1.184	1.206	1.247	1.336	1.392	1.388	1.405
NH	1.000	0.923	1.011	0.836	0.675	0.627	0.571	0.536	0.562	0.595
NJ	1.000	1.031	1.121	0.996	0.952	0.869	0.772	0.787	0.813	0.760
NM	1.000	0.972	1.070	0.956	0.990	0.976	0.909	0.989	1.004	0.957
NV	1.000	1.012	0.936	0.927	0.861	0.749	0.722	0.711	0.770	0.722
NY	1.000	1.004	0.890	0.785	0.803	0.676	0.576	0.525	0.503	0.474
OH	1.000	1.010	1.047	1.105	0.834	0.738	0.671	0.611	0.651	0.667
OK	1.000	0.954	1.004	0.820	0.907	0.896	0.814	0.865	0.898	0.820
OR	1.000	0.951	0.936	0.960	1.005	0.994	0.992	0.978	1.018	0.998
PA	1.000	0.988	0.967	1.000	0.894	0.593	0.524	0.502	0.522	0.508
RI	1.000	0.902	1.033	0.755	0.667	0.619	0.552	0.607	0.667	0.684
SC	1.000	0.993	1.076	1.159	1.121	1.125	1.121	1.105	1.141	1.086
SD	1.000	1.033	1.034	1.116	1.175	1.157	1.207	1.262	1.242	1.311
TN	1.000	0.972	1.134	1.228	1.173	1.241	1.199	1.048	1.048	1.014
TX	1.000	0.972	1.056	0.807	0.758	0.712	0.630	0.643	0.677	0.611
UT	1.000	1.042	1.026	1.074	1.078	1.088	1.171	1.215	1.237	1.256
VA	1.000	1.055	1.156	1.379	1.318	1.239	1.252	1.215	1.250	1.249
VT	1.000	1.042	1.038	1.041	1.058	1.058	1.058	1.126	1.046	1.055
WA	1.000	0.972	0.936	0.825	0.857	0.831	0.814	0.823	0.831	0.851
WI	1.000	1.022	1.032	1.067	1.065	1.109	1.086	1.085	1.082	1.096
WV	1.000	1.051	1.063	1.320	1.474	1.502	1.495	1.450	1.358	1.402
WY	1.000	0.996	1.053	1.127	1.155	1.210	1.317	1.384	1.405	1.446
U.S.	**1.000**	**0.995**	**1.055**	**1.003**	**0.991**	**0.978**	**0.954**	**0.961**	**0.977**	**0.947**

7.4.3 Regional Level

As we move to larger geographic levels of aggregation, emerging metrics gain importance in their usefulness to reflect performance against nationwide goals and objectives. Performance against national goals and priorities can be assessed by rolling up state and regional performance. The methodologies applicable to the affordability metrics are universally applicable at any geographic scale, and thus provide a consistent view of the metrics from the highest to the lowest spatial level.

Well-established cost-effectiveness metrics used as a matter of standard practice at the project and system level do not diminish in importance, but are likely aggregated and averaged as the level of geographic aggregation rises. Cost-burden metrics will become increasingly important at the regional level in the future.

7.4.4 National Level

There is national interest in measuring the effect of grid modernization efforts on customer affordability. Nationally, DOE is looking for insights into how the technologies and policies sponsored by the Department affect customer affordability. For the expected advances in technology to improve reliability, flexibility, resilience, security, and sustainability, it is important to know the financial effect on electricity customers. Costs will be incurred for new investments, but it may be possible to offset the costs passed on to customers using new products and services to provide benefits that mitigate annual net bills. These emerging affordability metrics provide a robust methodology for measuring and reporting affordability impacts nationally.

Figure 7.8 uses the EIA Form 861 data (EIA 2016a) to estimate the affordability headcount at the state level. The weighted-average customer cost was derived using the utility-system–level data for each state. State-level Census ACS data on household income were used for the income portion of the cost-burden calculation. Two observations confirm the analyses previously discussed. The 2015 data confirm what was observed in the 2009 RECS data. Electricity affordability is lower in the southern and Appalachian states than in states with generally higher electricity costs, such as in the northeastern states. This likely is a function of the average household incomes being somewhat lower in the southern and Appalachian states. Second, although there is a concentration of decreased affordability in the southern states, there is wide variation across the country.

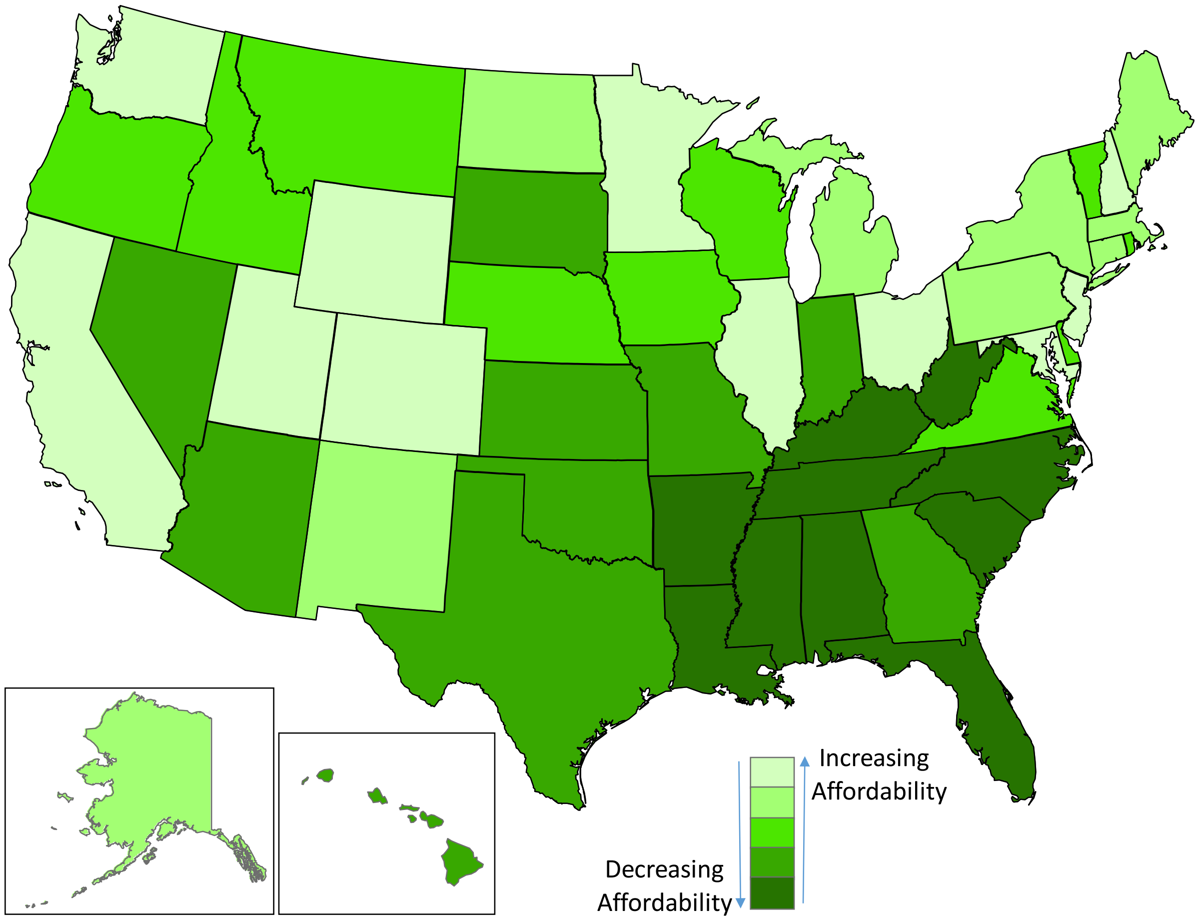

Figure 7.8. 2015 State-level residential customer affordability at the 3 percent cost-burden threshold.

Temporal variation in affordability also is important to understand as we look to measure the affordability impacts of ongoing grid modernization investments. The Alaska use-case will analyze this in more detail, but the RECS microdata from the previous surveys (EIA 1996, 2004, 2009a, 2009b, 2013) were examined at the aggregate national level to identify whether trends exist in the effect of the selected affordability threshold on the number of households with affordable electricity. Figure 7.9 plots the data from those surveys, and Table 7.1 reports the range of percentage of households with affordable electricity at key threshold values. The curves are somewhat similar and have inflection points in the range of 4–6 percent threshold values. The 2001 curve seems to be a bit of an outlier. Each curve was derived using the same approach. None of them account for the effects of cost subsidies and other factors affecting the cost burden. These additional factors would be expected to have similar effects in each analysis year, thus the relative comparison is still valid.

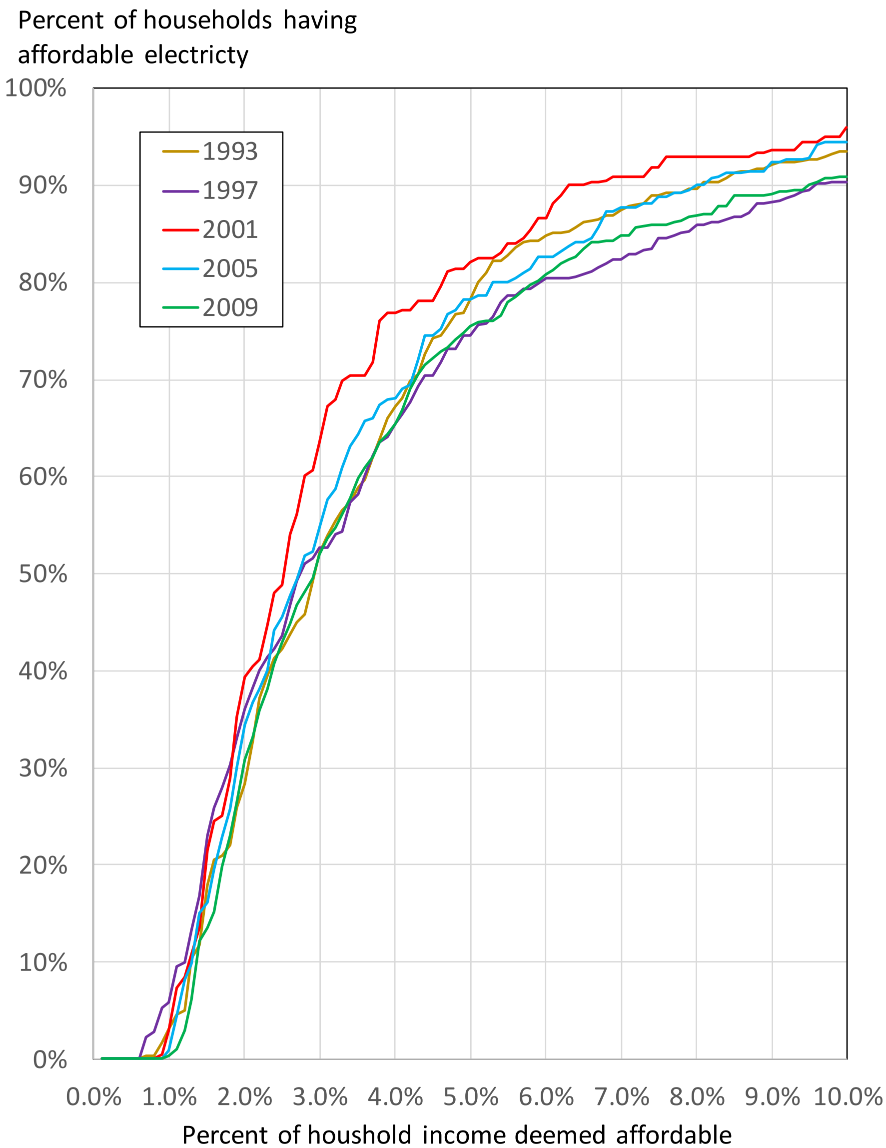

Figure 7.9. National level residential customer percentage of households with affordable electricity as a function of affordability threshold values (EIA 1996, 2004, 2009a, 2009b, 2013).

Table 7.4 takes slices of the curves in Figure 7.6 at the key threshold values (2–10 percent). These values suggest that baseline affordability varies over time (16 years) by about 6–12 percent depending on the threshold value selected, with wider variation in the lower thresholds. If 2001 were considered an outlier year, the variation would be even tighter. These ranges might inform the estimation of uncertainty associated with the affordability headcount metric.

Table 7.4. 1993–2009 affordability by threshold value from RECS microdata.

Threshold	1993	1997	2001	2005	2009
2%	28.4%	36.1%	39.3%	34.4%	30.8%
3%	52.1%	52.7%	63.5%	54.8%	52.0%
4%	67.3%	65.4%	76.9%	68.1%	65.4%
5%	78.3%	74.6%	82.1%	78.2%	75.5%
6%	84.9%	80.4%	86.6%	82.6%	80.9%
7%	87.5%	82.3%	90.9%	87.7%	84.8%
8%	89.6%	85.9%	93.0%	90.0%	86.9%
9%	92.1%	88.3%	93.7%	92.4%	89.1%
10%	93.5%	90.4%	96.0%	94.4%	90.9%

7.5 Customer-Data Use-Cases for Metrics

7.5.1 Alaska Microgrid Project

The GMLC program has funded the Alaska Regional Partnership, which is conducting the Alaska Microgrid Project (AMP). The AMP is designing renewable-based microgrids for two remote Alaskan villages, Chefornak and Shungnak, as a means of mitigating the extreme costs associated with transporting petroleum-based fuel to their remote locations. There is clear linkage with the affordability metric, because the reason for the AMP is to demonstrate that renewable resource solutions can reduce fuel costs, and therefore customer costs to villagers throughout Alaska.

Because these and most remote villages in Alaska have been receiving state subsidies to offset the high cost of fuel for local electricity generation, the state has detailed monthly customer cost data (unpublished 2016 data provided by Alaska Energy Authority) for each village participating in the Power Cost Equalization program (PCE). These data net out the cost of the PCE subsidies to reveal the net monthly cost faced by the customers. Data were provided for GMLC purposes for each year in the 2010–2015 period. Consistent data series were identified for 103 individual villages, including Chefornak and Shungnak, which also are covered in the Census ACS data for household income. The villages range in size from towns of more than 1,000 people to tiny outposts with just a few residents. Some of the villages are grouped together in the PCE data, most likely indicating that they may share the same power generation resources.

The AMP has value for demonstrating the affordability metrics for two reasons. It covers the entire state with a consistent methodology for estimating customer cost and accounts for the subsidy portion received by customers to yield a true net bill. Every village is analyzed and reported using the same approach.

There are two limitations in the data. The data are not customer-specific data, like those most utilities would have. Thus, the reported costs represent residential customer averages at the village level. In the Alaska village case, the dwellings would be expected to be somewhat homogeneous, without great variation in floor space or heating demand. Therefore, the village average cost per customer may not be unreasonable. In addition, there are no customer-level income data. As mentioned, there are village-level household income ACS data for each of the 103 villages analyzed for 16 income bins.

7.5.2 Baseline Metrics

Using the monthly summarized billing data for 103 villages, the village weighted-average customer cost burden was calculated by dividing the annual net cost per customer by the midpoint of each of the ACS household income bins, as described in Section 7.3.4, then weighting by the number of households in each income bin. These weighted-average village cost burdens are reported in the left third of Table 7.5. Based on the assumption that fuel use would be evenly split between heating and electricity generation, an affordability threshold of 3 percent was selected, consistent with the approached outlined by Colton (2011) and discussed in Section 7.3.1.1. The village-level affordability gap was calculated based on the approach documented in Section 7.3.2, and is shown in the center section of Table 7.5. The affordability gap index, which tracks the movement of the affordability gap through time, was calculated relative to 2010 and based on the approach in Section 7.3.3 and is shown in the right third of Table 7.5.

Table 7.5 presents results for all 103 villages analyzed, but some specific observations are possible for the AMP villages of Cherfornak and Shungnak. Chefornak shows improving electricity affordability, based on declining average cost burdens. The declining cost burden is happening concurrently with increasing-to-level electricity costs, because incomes are increasing at a faster pace than electricity costs. The increasing affordability has accelerated in recent years. Shungnak is facing decreasing affordability as the average cost burden is increasing because of increased electricity costs coupled with declining incomes. The affordability gap has widened in the last couple of years. Taken together, all 103 villages, in aggregate, have been relatively stable over the 2010–2015 period, and the overall average cost burden was just over 3 percent each year.

Table 7.6 lists the village-level affordability headcount metrics. Chefornak shows improving electricity affordability, based on markedly fewer households facing unaffordable electricity. The increased proportion of households with affordable electricity is due in part to more households in the upper income bins compared to 2010 and 2011. The increasing affordability has accelerated in recent years, and 2015 was a good year for income growth and net electricity cost decline. The proportion of households in Shungnak with unaffordable electricity has accelerated to an upward trend in the last 3–4 years, as the average cost burden is increasing due to higher electricity costs relative to 2010. The headcount metric has rebounded back to its 2010 level after declining from 2010–1012. Taken together, all 103 villages in aggregate have been relatively stable over the 2010–2015 period, and the overall affordable headcount was at just over 32 percent of households each year.

Table 7.7 illustrates the importance of the selection of the affordable threshold value. This table presents the affordability headcount metric and associated gap index for several alternative threshold values. By choosing alternative thresholds, the implications can change substantially. For example, given the results discussed for 3 percent thresholds, by increasing the affordability threshold to 5 percent or greater, intuitively, the percentage of households with affordable electricity grows substantially. At the aggregate village level, the number of households also changes markedly, but the overall trend reflected in the gap index remains level. However, the gap index for individual villages can fluctuate substantially.

The case of Alaskan villages is useful for testing the metrics using summarized data with the customer subsidies netted out. However, given the very small size of these locations and the special circumstances in which their electricity is generated and delivered, this case may not best represent the experience in the rest of the nation. However, the reliance on relative as opposed to absolute numerical comparisons makes the methods widely applicable and useful at any scale.

Table 7.5. Alaska village baseline affordability metrics (2010–2015).

Village	Average Proportion of Income Spent on Electricity (Customer Burden) (%)						Affordability Gap @ 3% Threshold						Affordability Gap Index (2010 = 1)					
	2010	2011	2012	2013	2014	2015	2010	2011	2012	2013	2014	2015	2010	2011	2012	2013	2014	2015
Chefornak	3.21	3.00	2.68	2.86	2.52	2.28	1.07	1.00	0.89	0.95	0.84	0.76	1.00	0.94	0.84	0.89	0.79	0.71
Shungnak	4.28	3.69	3.71	3.91	3.85	4.02	1.43	1.23	1.24	1.30	1.28	1.34	1.00	0.86	0.87	0.92	0.90	0.94
All Villages (103) Weighted Average	3.08	3.03	3.01	3.09	3.10	3.10	1.03	1.01	1.00	1.03	1.03	1.03	1.00	0.98	0.98	1.00	1.01	1.01

Table 7.6. Alaska village baseline affordability headcount metrics (2010–2015).

Village	Percent of HH with Unaffordable Electricity @ 3% Threshold						Affordability Headcount Gap Index					
	2010	2011	2012	2013	2014	2015	2010	2011	2012	2013	2014	2015
Chefornak	38.0%	36.1%	33.8%	38.6%	31.3%	22.7%	1	0.95	0.89	1.01	0.82	0.60
Shungnak	44.4%	40.3%	30.9%	36.8%	37.5%	44.9%	1	0.91	0.69	0.83	0.84	1.01
Villages (103) Weighted Average	32.1%	32.6%	32.5%	33.2%	32.9%	32.6%	1	1.02	1.02	1.04	1.03	1.02

Table 7.7. Electricity affordability metrics for Chefornak and Shungnak using alternative threshold values.

Village	Affordability Threshold	Percent of HH with Unaffordable Electricity						Affordability Headcount Gap Index					
		2010	2011	2012	2013	2014	2015	2010	2011	2012	2013	2014	2015
Chefornak	1.0%	69.0%	75.0%	74.0%	80.7%	85.0%	79.5%	1	1.09	1.07	1.17	1.23	1.15
	1.5%	66.2%	70.8%	62.3%	65.1%	66.3%	55.7%	1	1.07	0.94	0.98	1.00	0.84
	2.0%	50.7%	51.4%	46.8%	47.0%	47.5%	37.5%	1	1.01	0.92	0.93	0.94	0.74
	2.5%	38.0%	36.1%	35.1%	39.8%	37.5%	28.4%	1	0.95	0.92	1.05	0.99	0.75
	3.0%	38.0%	36.1%	33.8%	38.6%	31.3%	22.7%	1	0.95	0.89	1.01	0.82	0.60

	3.5%	32.4%	27.8%	22.1%	27.7%	17.5%	13.6%	1	0.86	0.68	0.86	0.54	0.42
	4.0%	32.4%	27.8%	22.1%	27.7%	17.5%	13.6%	1	0.86	0.68	0.86	0.54	0.42
	4.5%	22.5%	20.8%	15.6%	18.1%	12.5%	9.1%	1	0.92	0.69	0.80	0.55	0.40
	5.0%	22.5%	20.8%	15.6%	18.1%	12.5%	9.1%	1	0.92	0.69	0.80	0.55	0.40
	5.5%	18.3%	15.3%	9.1%	8.4%	3.8%	4.5%	1	0.83	0.50	0.46	0.20	0.25
	6.0%	18.3%	15.3%	9.1%	8.4%	3.8%	4.5%	1	0.83	0.50	0.46	0.20	0.25
	1.0%	93.7%	92.2%	94.1%	88.2%	92.2%	89.9%	1	0.98	1.00	0.94	0.98	0.96
Shungnak	1.5%	93.7%	88.3%	85.3%	82.4%	82.8%	79.7%	1	0.94	0.91	0.88	0.88	0.85
	2.0%	71.4%	70.1%	64.7%	64.7%	60.9%	68.1%	1	0.98	0.91	0.91	0.85	0.95
	2.5%	65.1%	59.7%	50.0%	47.1%	39.1%	52.2%	1	0.92	0.77	0.72	0.60	0.80
	3.0%	44.4%	40.3%	30.9%	36.8%	37.5%	44.9%	1	0.91	0.69	0.83	0.84	1.01
	3.5%	22.2%	19.5%	23.5%	27.9%	34.4%	40.6%	1	0.88	1.06	1.26	1.55	1.83
	4.0%	22.2%	16.9%	19.1%	25.0%	28.1%	33.3%	1	0.76	0.86	1.13	1.27	1.50
	4.5%	22.2%	16.9%	19.1%	25.0%	28.1%	33.3%	1	0.76	0.86	1.13	1.27	1.50
	5.0%	22.2%	16.9%	19.1%	25.0%	28.1%	33.3%	1	0.76	0.86	1.13	1.27	1.50
	5.5%	22.2%	16.9%	19.1%	25.0%	28.1%	33.3%	1	0.76	0.86	1.13	1.27	1.50
	6.0%	22.2%	16.9%	16.2%	20.6%	21.9%	21.7%	1	0.76	0.73	0.93	0.98	0.98
All Villages Weighted Average	1.0%	75.0%	74.0%	74.5%	75.6%	74.9%	74.9%	1	0.99	0.99	1.01	1.00	1.00
	1.5%	59.4%	58.5%	58.2%	60.5%	60.9%	60.0%	1	0.98	0.98	1.02	1.02	1.01
	2.0%	46.0%	46.2%	46.1%	47.4%	47.4%	47.3%	1	1.00	1.00	1.03	1.03	1.03
	2.5%	38.5%	38.7%	38.7%	39.8%	39.2%	39.4%	1	1.01	1.01	1.04	1.02	1.03
	3.0%	32.1%	32.6%	32.5%	33.2%	32.9%	32.6%	1	1.02	1.02	1.04	1.03	1.02
	3.5%	26.8%	26.4%	26.4%	27.7%	27.7%	27.8%	1	0.99	0.99	1.03	1.03	1.04
	4.0%	23.8%	22.8%	22.4%	23.3%	23.3%	23.6%	1	0.96	0.94	0.98	0.98	0.99
	4.5%	20.4%	19.6%	19.2%	20.2%	20.4%	20.6%	1	0.96	0.94	0.99	1.00	1.01
	5.0%	18.0%	17.3%	17.1%	17.9%	18.1%	18.2%	1	0.96	0.95	1.00	1.01	1.01
	5.5%	16.0%	15.2%	15.1%	15.9%	16.0%	16.1%	1	0.95	0.95	1.00	1.00	1.01
	6.0%	14.1%	13.1%	13.0%	13.9%	14.2%	14.0%	1	0.93	0.92	0.98	1.00	0.99

7.5.3 Future Use-Cases

The affordability metric needs to be further tested and demonstrated using meaningful test cases of value to specific stakeholders. A number of considerations in the application of these metrics require testing.

One valuable test would be to compare the application of public data sources to the methodology presented to determine any meaningful differences in results based on the use of alternate data sources. For example, does it make a meaningful difference to use Form 861 customer cost data, as opposed to carefully analyzing the RECS microdata, to extract the same information?

The ideal test would be to use anonymized customer billing data with the documented methodology. If the cost-burden metric could be built up from individual customer data, including household income, then most of the drawbacks of assumption making required to use public data sources would be overcome. Further, such an approach could be coupled with the approach using public data sources and the results compared. Would the two methods yield significantly different results?

An important use-case would be to engage a utility commission on a question of importance to them in the area of affordability and expected future costs of grid modernization. It would seem useful to a commission to know how cost burdens might change and where cost burdens are most severe.

7.6 Links to Other Metrics

Affordability is linked to all other metrics by the estimation of net costs. Changes in any other metric domain will have companion effects on cost-effectiveness and customer affordability. The fact that linkages exist to affordability is well understood. For example, utility investments to improve reliability, resilience, and flexibility may result in costs that would be passed on to customers – reducing the affordability of their electric service. At the same time, these investments may enable customers to take advantage of new demand-side services which could result in benefits or credits to the cost of their electric service – increasing the affordability of their electric service. The metrics developed will enable the linkage of customer cost and benefit valuation with investment required to modernize the grid.

What may be of interest is to engage the other metrics from the affordability context by asking the questions:

- What can be done in the flexibility or reliability domain to make electricity more affordable?
- What new products and services will a modernized grid enable that might offset costs required to enable them?
- What ancillary benefits from increased sustainability, resilience, and security can be translated to improved affordability?

7.7 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 affordability 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 ERPI, Minnesota PUC, Colorado State Energy Office, and the

Washington Utilities and Transportation Commission. The following is a synopsis of key points made during the 1.5 hour briefing:

- Technical considerations:
  - A time-trend of the affordability metrics is very useful for assessing the changes over time. Perhaps it is more useful/appropriate than the disaggregation across geographic areas that could be influenced by different consumption patterns. For instance, coastal climate zones versus inland zones.
  - Metrics should be defined by seasons, such that consumption for cooling can be isolated from heating end-uses. If we report only annual affordability metrics, the monthly spikes will be reduced in the annualization process, thus underestimating some of the more season-related burdens faced by low-income customers. Addressing seasonality could also support explanation of consumption-based driver.
  - In addition to the current definition of affordability metrics, team should consider supplementing the affordability metrics with a $/kWh indicator in order to isolate the rate driver in the affordability values from the consumption-based driver.
  - Income data may be difficult to obtain. Reviewers from Washington and Colorado indicated that the data must be "air-tight" in order to use them in PUC rate proceedings. Billing data are available by the utility company.
  - Consider whether the affordability metric should include the total or certain portions of the electricity bill. For instance, charges such as transmission and distribution charges, taxes, demand charges could be separated and not included to be more consumption based.
  - The affordability metrics are very much aligned with the sustainability research EPRI is doing.
- Affordability metrics are very useful from the reviewers' perspective (primarily from a state perspective):
  - In Colorado, State Energy Office is interested in affordability from a low-income residential customer's perspective.
  - The next customer group for which affordability metrics should be demonstrated is the industrial sector. Industrial customers have been vocal about affordable power concerns via their interveners. Many have threatened states with moving their operations to lower-cost jurisdictions. The challenge is to deal with the very high demand charge not necessarily the usage-based portion of the electricity bill.
  - Reviewers suggested exploring the piloting of this metric development with a specific utility.
- Usability and practicality of applying affordability metrics: A high degree of certainty of the correctness of income data must exist for metrics to be used in a meaningful way at rate proceedings.
  - Perhaps affordability metrics could be used in the context of value-creating attributes or metrics such as resilience. This would allow trade-off analysis to weight affordability versus resilience.
  - A good use of affordability metrics would be to assess investments in residential low-income areas.
  - Utility companies could potentially adopt affordability metrics as a part of their voluntary sustainability reporting.
- Consider what is the best way for the affordability metrics to gain traction in the utility community:

  - Via the voluntary route, such that a utility adopts affordability metrics (or a portion of them) as a part of its sustainability reporting based on their own customer bill data (appropriate income data may still be an issue); or
  - Via requirements by PUCs for IRP report of rate proceedings.
- Engage with stakeholders to explore priorities of affordability metrics within the scope of the 6 metric categories.

8.0 Physical and Cyber Security

8.1 Definition

Security is defined as the ability to resist external disruptions to the energy supply infrastructure caused by intentional physical or cyber-attacks or by limited access to critical materials from potentially hostile countries. As applied to physical/cyber security, security prevents external threats and malicious attacks from occurring and affecting system operation. Specifically, with respect to supply chain, security means maintaining and operating the system with limited reliance on supplies (primarily raw materials) from potentially unstable or hostile countries. These operational definitions are founded in principles outlined in Presidential Policy Directive 21 (Obama 2013), "Critical Infrastructure Security and Resilience," which defines "security" as "reducing the risk to critical infrastructure by physical means or defense cyber measures to intrusions, attacks, or the effects of natural or man-made disasters."

8.2 Established Metrics

Security metrics for the electric sector have recently seen considerable development (Brotby 2009; Bakshi et al. 2011); however, there are numerous approaches but no consensus on which of the numerous security metrics should be used. One reason is that "security" does not possess a well-understood canon of techniques for measurement.

Instead of security metrics, the security community generally uses annualized loss expectancy (ALE) as a means to justify its security budget (Seger 2003; CGI Security undated; Jaquith 2007). ALE is the monetary loss that can be expected for an asset due to a risk over a 1-year period and is calculated by multiplying the single loss expectancy (SLE) by the annualized rate of occurrence (ARO):

$$\text{ALE} = \text{SLE} \times \text{ARO}$$

There are issues with applying the ALE approach to the electric sector, especially in the case of planning for a deliberate attack from an intelligent adversary. The electric sector does not have actuary tables derived from decades of data collection that can tell precisely what adversaries will do, how often they will do it, and how much it will cost the electric sector when they do it. The number of unknowns that would have to be modeled to predict adversarial behaviors and the margin of error associated with modeling those unknowns would make the estimates far too uncertain for the ALE approach to be useful. In addition, the ALE approach is highly qualitative in terms of its inputs and does not provide metrics of progress that display the status of physical and/or cyber security in comparison with the final security goals of an electric utility.

8.3 State-of-the-Art

Quantifying the benefits of managing cyber and physical security in the electric industry is challenging. The field of security metrics is relatively new compared to the engineering measures of a utility's traditional power systems. The following sections provide examples of recently developed security metrics (the following is not meant to be all-inclusive).

8.3.1 NERC Bulk Electric System Security Metrics

In 2012, a new Bulk Electric System Security Metrics Working Group (BESSMWG) developed a metrics framework for physical and cyber security metrics that measure and track historic performance (i.e., lagging) and provide leading indicators of future issues. The BESSMWG considered general categories of metrics related to security performance including publicly available historical information about actual physical and cyber events as well as leading indicators of information sharing and publicly available metrics of global cyber vulnerabilities relevant to the electric sector; no classified information was considered. The current NERC Bulk Electric System (BES) security metrics (NERC 2015) are as follows:

- reportable cyber security incidents (that result in a loss of load)
- reportable physical security events (that occur over time as a result of threats to a facility or BES control center or damage or destruction to a facility)
- Electricity Sector Information Sharing and Analysis Center (E-ISAC) membership (the number of E-ISAC member organizations)
- industry-sourced information sharing (the number of E-ISAC Incident Bulletins, currently known as Watch List entries)
- global cyber vulnerabilities (the number of global cyber vulnerabilities with a Common Vulnerability Scoring System [CVSS] [NIST 2017] of 7 or higher).

8.3.1.1 Maturity Level

These security metrics have been in use since 2014.

8.3.1.2 Applications

The NERC BES security metrics have been applied for the U.S. bulk power system.

8.3.1.3 Data Source and Availability

The challenges in applying NERC's security metrics include limited historical data, limited ability to normalize available data, limited response to a changing threat landscape, and the need for sensitive information.

8.3.1.4 EPRI Cyber Security Metrics

Cyber security as a field is typically defined by security standards and guidelines. Cyber security metrics have been developed by EPRI for the bulk power system that are intended to provide example actionable metrics that utilities may leverage to create a cyber security metrics program (EPRI 2016c). In 2015, EPRI collaborated with members and external partners to create and vet a template for creating security metrics. In 2016, EPRI developed a set of potential metrics and data points that may be used in a security metrics program. These metrics were categorized at three different levels in a hierarchical structure: strategic, tactical, and operational. Figure 8.1 displays the connected nature of the metrics from strategic level, executive-level summary metrics, to tactical, management level summary metrics, down to operational day-to-day metrics calculated directly from data points gathered throughout the day.

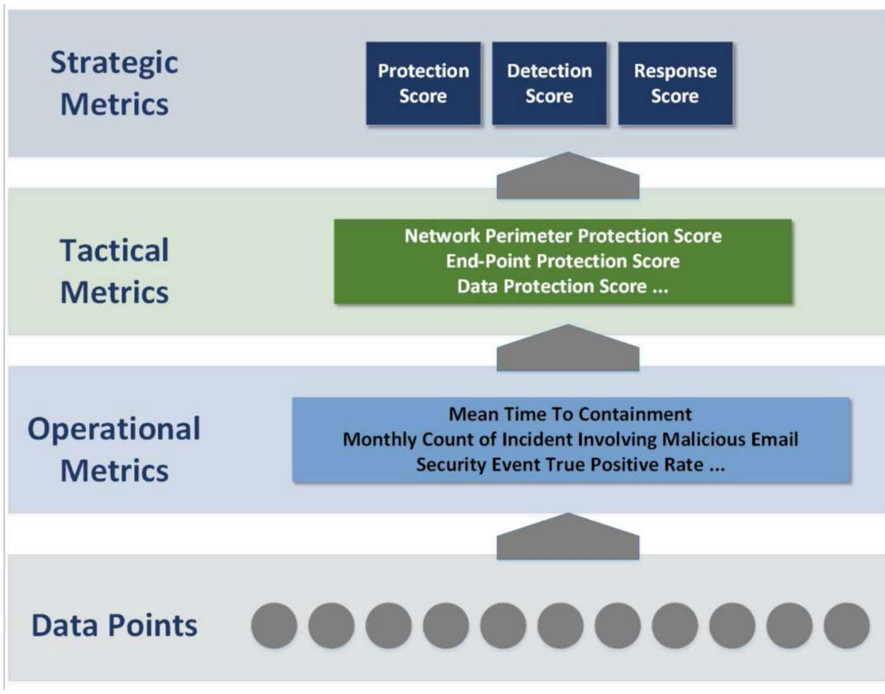

Figure 8.1. EPRI hierarchy of metrics (EPRI 2016c).

Strategic- and tactical-level metrics are represented by a normalized value between 0 and 10, where a higher value indicates better performance. The methodology for aggregating and normalizing the metrics is currently under development at EPRI. Operational-level metrics are derived directly from the data points consisting of various operational statistics collected from different points in utility operations and represent one specific aspect of security controls in a target system. Table 8.1 and Table 8.2 detail EPRI's strategic- and tactical-level cyber security metrics for measuring the effectiveness of cybersecurity program for the electric sector. Information on naming nomenclature can be found in the associated EPRI report (EPRI 2016c).

Table 8.1. EPRI's strategic metrics and associated tactical metrics.

Metric ID	Strategic Metric	Tactical Metric ID	Tactical Metric Name
S-PS	Protection Score	T-NPPS	Network Perimeter Protection Score
		T-EPS	End-point Protection Score
		T-PAS	Physical Access Control Score
		T-HSS	Human Security Score
		T-NVS	Core Network Vulnerability Control Score
		T-NAS	Core Network Access Control Score
		T-DPS	Data Protection Score
		O-I-MTBI	Mean Time Between Security Incidents
		T-SMS-P	Security Management Score -Protection
S-DS	Detection Score	T-TAS	Threat Awareness Score
		T-TDS	Threat Detection Score
		T-SMS-D	Security Management Score - Detection
S-RS	Response Score	T-IRS	Incident Response Score
		T-SMS-R	Security Management Score - Response

Table 8.2. EPRI's tactical metrics and associated operational metrics.

Metric ID	Tactical Metric Name	Operational Metric ID	Operational Metric Name
T-NPS	Network Perimeter Protection Score	O-N-MAPS	Mean Access Point Protection Score
		O-N-MWAPS	Mean Wireless Access Point Protection Score
		O-N-MIPS	Mean Internet Traffic Protection Score
		O-I-MCME	Mean Count-M Malicious Email
		O-I-MCMU	Mean Count-M Malicious URL
		O-I-MCNP	Mean Count-M Network Penetration
T-EPS	End-point Protection Score	O-U-MSDPS	Mean Stationary End-Point Protection Score
		O-U-MMDPS	Mean Mobile End-Point Protection Score
		O-I-MCMW	Mean Count-M Malware
		O-I-MCMD	Mean Count-M Mobile End-Point
		O-I-MCSD	Mean Count-M Stationary End-Point
T-PAS	Physical Access Control Score	O-A-MPACS	Mean Physical Access Control Score
		O-I-MPAV	Mean Count-M Physical Access Violation
T-HSS	Human Security Score	O-H-MHSS	Mean Human Security Score
		O-I-MCSE	Mean Count-M Social Engineering
T-NVS	Core Network Vulnerability Control Score	O-A-MAC	Mean Asset Connectivity
		O-A-MAP	Mean Asset Proximity to Hostile Network
		O-A-MVRS	Mean Asset Vulnerability Risk Score
		O-A-MNVRS	Mean Network Vulnerability Risk Score
		O-I-MCNP	Mean Count-M Network Penetration
T-NAS	Core Network Access Control Score	O-A-MAC	Mean Asset Connectivity
		O-A-MAP	Mean Asset Proximity to Hostile Network
		O-A-MACS	Mean Asset Access Control Score
		O-A-MNACS	Mean Network Access Control Score
		O-I-MCNP	Mean Count-M Network Penetration
T-DPS	Data Protection Score	O-D-MDCS	Mean Data Confidentiality Score
		O-D-MDIS	Mean Data Integrity Score
		O-D-MDAS	Mean Data Availability Score
		O-I-MCDL	Mean Count-M Data Leak/Loss
T-SMS	Security Management Score	O-M-SBR	Security Budget Ratio
		O-M-SPR	Security Personnel Ratio
		O-M-CRTS	Cybersecurity Risk Tolerance Score
T-TAS	Threat Awareness Score	O-T-IES	Organization Threat Awareness Score
		O-T-MTIA	Mean Time from Intelligence to Action
		O-T-MTIP	Mean Time from Intelligence to Protection
		O-T-THES	Threat Hunting Effectiveness Score

Table 8.2. (contd)

Metric ID	Tactical Metric Name	Operational Metric ID	Operational Metric Name
T-TDS	Threat Detection Score	O-T-MITP	Mean Threat Intelligence True Positive Rate
		O-T-MCI	Mean Count-M Threat Intelligence
		O-E-METP	Mean Security Event True Positive Rate
		O-E-MC	Mean Count-D Security Events
		O-T-THTP	Mean Threat Hunting True Positive Rate
		O-T-MCH	Mean Count-M Threat Hunting Intelligence
		O-I-MCH	Mean Count-M High Severity Incidents
		O-I-MCM	Mean Count-M Medium Severity Incidents
		O-I-MCT	Mean Count-M Total Incidents
T-IRS	Incident Response Score	O-I-MTTD	Mean Time to Discovery
		O-I-MCMSI	Mean Count-M Missed Security Incidents
		O-E-SEMS	Security Event Management Score
		O-I-MTTC	Mean Time to Containment
		O-I-MTR	Mean Time to Recovery
		O-I-MTTA	Mean Time to First Action
		O-I-MCRM	Mean Cost of Response in Man-Hour (existing resource)
		O-I-MCRX	Mean Cost of Response in Dollar Amount (extra resource)

Unlike strategic or tactical metrics, operational metrics are not normalized into a numerical value between 0 and 10. Currently, 49 operational metrics are being considered by EPRI (please refer to the report for further information – EPRI 2016c).

8.3.1.5 Maturity Level

EPRI stated in its report that there are a number of topics for future research that may include the following:

- data collection strategies including specific information technology and operational technology considerations on extracting data from manual sources;
- identification of security tools required for data collection;
- mapping of each metric to NERC Critical Infrastructure Protection (CIP), the National Institute of Standards and Technology (NIST) Cybersecurity Framework (CSF), and the Cybersecurity Capability Maturity Model (C2M2);
- development of a methodology for rolling up the lower level metrics to higher level metrics; and
- normalization techniques for metric scores.

EPRI indicates that it intended to continue the discussion among members and external partners to aggregate metrics for industry benchmarking.

8.3.1.6 Applications

In addition to finalizing the methodology, EPRI intends to work with members to pilot the methodology. Through the pilot program, the utilities will identify the best approach to adopting security metrics in alignment with their own organizational goals and risk management strategies.

8.3.1.7 Data Source and Availability

Application of the EPRI cyber security metrics would require utility-specific data that could be considered sensitive and possibly business-proprietary. This would limit the use of this approach to utilities and it may not be available on a regional or national scale.

8.3.2 DHS Cyber Infrastructure Survey Tool

The Cyber Infrastructure Survey Tool (C-IST) is used by the DHS Office of Cybersecurity & Communications (CS&C) to evaluate controls-based cyber protection and resilience measures within critical infrastructure sectors. The C-IST is a structured, interview-based assessment focusing on over 80 cybersecurity controls grouped under 5 key surveyed topics. The key principles of the C-IST method focus on protective measures, threat scenarios, and a service-based view of cybersecurity in the context of the following five surveyed topics:

- cybersecurity management,
- cybersecurity forces,
- cybersecurity controls,
- cyber incident response, and
- cyber dependencies.

The cybersecurity controls surveyed within the C-IST broadly align with the NIST CSF.

8.3.2.1 Maturity Level

These security metrics have been in use since 2014.

8.3.2.2 Applications

The DHS C-IST is used by the DHS CS&C's Cyber Security Advisors.

8.3.2.3 Data Source and Availability

The data for the DHS C-IST are provided by the critical infrastructure asset owners and operators. This information is considered sensitive, non-public information by industry and as such is designated as Protected Critical Infrastructure Information (PCII) and subject to handling and dissemination restrictions. The PCII limitations on use of this data set would be enforced when the information is associated with the facility or owner/operator. If the data is sanitized of identifying information, it can be more widely shared and potentially used in development of cyber security metrics. The sanitization process might limit the use of this data set to only national- or regional-level aggregated metrics where individual sites or operators and their vulnerabilities are not identified.

8.3.3 DOE Electricity Subsector Cybersecurity Capability Maturity Model

The Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2) was developed by the DOE to improve electricity subsector cybersecurity capabilities and to understand the cybersecurity posture of the energy sector. The ES-C2M2 was derived from the Cybersecurity Capability Maturity Model (C2M2) which was developed by DOE using industry-accepted cybersecurity practices to assist all types of organizations in evaluating their cybersecurity programs. The model provides maturity indicators that provide the organization information about their cybersecurity capabilities and risks during normal and crisis operations. In additional to the C2M2 core, the ES-C2M2 contains reference material and implementation guidance specific to the electric subsector (DOE 2016a).[1] The maturity indicators in the ES-C2M2 can be used to baseline and gauge the effectiveness of an electric organization's cybersecurity. The results allow an organization to quickly assess their current capabilities and outline plans for future states. As a one-day self-evaluation, the C2M2 provides a relatively easy entry into the world of security metrics. However, C2M2 does not measure the performance of each domain, which is needed for security metrics.

8.3.3.1 Maturity Level

The ES-C2M2 tool has been available to public since January 2012.

8.3.3.2 Applications

The DOE ES-C2M2 was developed in partnership with NERC, EEI, National Rural Electric Cooperative Association, APPA, and numerous utilities, including Southern California Edison, Bonneville Power Administration, PG&E, ERCOT, Dominion Resources, and American Electric Power.

8.3.3.3 Data Source and Availability

The data for the DOE ES-C2M2 are provided by the critical infrastructure asset owners and operators. According to the C2M2 FAQ sheet (DOE 2014), DOE does not retain any utility-provided information or results from the self-assessments.

8.3.4 California Public Utilities Commission Physical Security Metrics

The CPUC examined grid security at all levels of the electric supply system, including the distribution level and has recommended a possible methodology for utility electric distribution system physical security planning (Brinkman, et. al. 2015). Existing CPUC rules establish various requirements regarding distribution system physical security, and California Senate Bill 699 mandates CPUC action to develop rules for physical security for the distribution system in a new proceeding or new phase of an existing proceeding (CA Legislative Assembly 2014). Examples of quantitative metrics considered by the CPUC for distribution physical security measures include tracking the following:

- copper theft
- successful or unsuccessful intrusion or attack

[1] It should be noted that there is also an Oil and Natural Gas Subsector Cybersecurity Capability Maturity Model (ONG-C2M2) that comprises a maturity model, an evaluation tool, and DOE-facilitated self-evaluations specifically tailored for the oil and natural gas subsector.

- false or nuisance alarms
- the condition of all monitoring equipment (e.g., number of malfunctions of security equipment)
- performance of security personnel in training exercises and on tests, and
- instances of vandalism or graffiti.

The CPUC stated that it was virtually impossible for regulators to establish a "one-size-fits-all" approach that would work for all utilities, and concluded that a performance-based approach with reliable metrics lends itself well to a system that has varied equipment in the electric sector.

8.3.4.1 Maturity Level

A CPUC June 2014 physical security workshop indicated that all California electric utilities use some sort of risk and vulnerability assessment to plan for physical security protections, and use similar physical threat mitigation techniques.

8.3.4.2 Applications

The CPUC examined grid security at all levels of the electric supply system in California during 2014, including the distribution level, and is re-evaluating its existing policies and oversight activities for electric system security.

8.3.4.3 Data Source and Availability

A portion of the data needed for these metrics is available from public literature, but data on the condition of monitoring equipment, problems with access control, etc. would have to be provided by each electric utility. This type of information about the electric system would be confidential for security concerns. As such, it may be difficult to apply this approach on a regional and national level without heavy involvement of local electric utilities.

8.3.5 DHS Infrastructure Survey Tool

The Infrastructure Survey Tool (IST) is used to collect a series of physical security metrics developed by DHS, through their Enhanced Critical Infrastructure Protection (ECIP) Initiative. This approach uses a methodology for assessing infrastructure risk and resilience to a variety of natural and man-made hazards. The IST has more than 1,500 data collection points covering 5 major security-related components: physical security, security force, security management, information sharing, and security activity history/background. The gathered information is compiled into a metric called the Protective Measures Index (PMI) (Argonne 2013), which is used to assist DHS in analyzing sector (e.g., Energy) and subsector (e.g., Electricity, Oil, and Natural Gas) vulnerabilities to identify potential ways to reduce vulnerabilities and to assist in preparing sector risk estimates. The PMI combines the information collected in five categories, which are also called PMI Level 1 components (Figure 8.2).

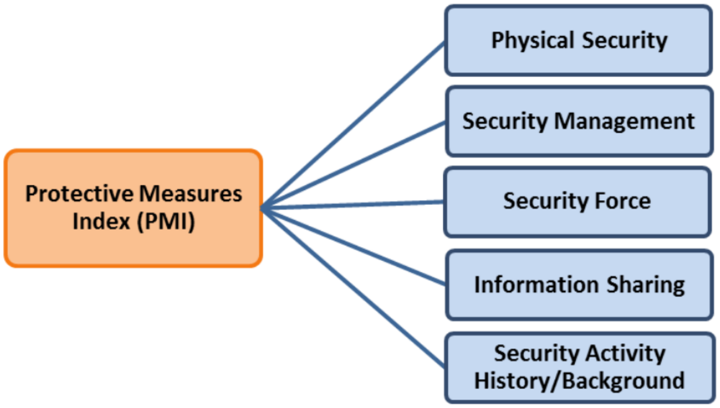

Figure 8.2. Level 1 Components of the Protective Measures Index

The PMI structures the information collected in five categories—namely, Physical Security, Security Management, Security Force, Information Sharing, and Security Activity History/Background[1] —to characterize the protective posture of a facility. The overall PMI consists of a weighted sum of the five major security-related components (W_i), and scaling constant (d_i) indicating its relative importance:

$$PMI = \sum d_i \times W_i$$

8.3.5.1 Maturity Level

These security metrics have been applied by DHS since 2009 (Fisher and Norman 2010).

8.3.5.2 Applications

From the period between January 2011 and January 2016, the DHS has conducted over 4,300 security surveys on critical infrastructure and key resources, which included over 400 security surveys of electric subsector facilities.

8.3.5.3 Data Source and Availability

The data collected as part of a DHS IST are provided by the critical infrastructure asset owners and operators. The data are validated as PCII and are protected under the Critical Infrastructure Information Act of 2002 from the Freedom of Information Act; state, local, tribal, and territorial disclosure laws; use in regulatory actions; and use in civil litigation. Only authorized federal, state, and local security analysts are allowed to handle PCII data. (See the Final Rule at 6 CFR Part 29, published in the *Federal Register* on September 1, 2006, for more information on PCII).

[1] The "Physical Security" component in the PMI approach refers to measures and features that protect a facility and its buildings, perimeter, and occupants from intrusion; "Security Management" refers to plans and procedures a facility has in place to deal with security issues; "Security Force" refers to a special group of employees or contractors with security duties; "Information Sharing" refers to the exchange of hazard and threat information with local, State, and Federal agencies; and "Security Activity History/Background" collects information related to previous vulnerability assessments and new protective measures that a facility may have implemented within the last year to improve its security posture.

8.4 Emerging Metrics

Baseline metrics are calculated with existing electric facility security information collected via the IST. The baseline metrics listed in Section 0 would be augmented by emerging metrics or enhanced existing metrics designed to fill the gaps identified through the security metrics reviews. Discussion with utilities, industry trade associations, DHS, and DOE decision-makers might be necessary to ensure the necessary and sufficient breadth of security activities and mitigation activities is captured by the developed metrics. The proposed framework for security metrics provides consistent and repeatable application and calculation across all utilities while maintaining flexibility to account for organization of facility security objectives given their specific threat landscape and security priorities. In general, security objectives focus on preventing, detecting, mitigating, and recovering from attacks on the system.

8.4.1 Revised Protective Measures Index

8.4.1.1 Potential or Proposed Approach

The DHS IST enables users to gather critical infrastructure data, including vulnerability, resilience, and consequence information, which provide a complete context for meeting users' mission-specific needs to identify vulnerabilities and develop mitigation strategies. As described in Section 8.3.5, the data collected with the IST are weighted and scored, enabling DHS to conduct comparisons of like sets of infrastructure. The DHS IST is the "most widely applied security survey method that can identify security gaps and trends, and enable detailed analyses of site and sector vulnerabilities" (DHS 2015).

Figure 8.3 displays the process to create a revised protective measures index is shown in. The current IST questions are answered by site personnel but could conceivably be answered by public data sets. It is proposed that the individual IST questions about physical security which are used in the PMI calculation be examined to establish whether these IST questions require sensitive security information available only from site personnel or whether public data could supply the required information.

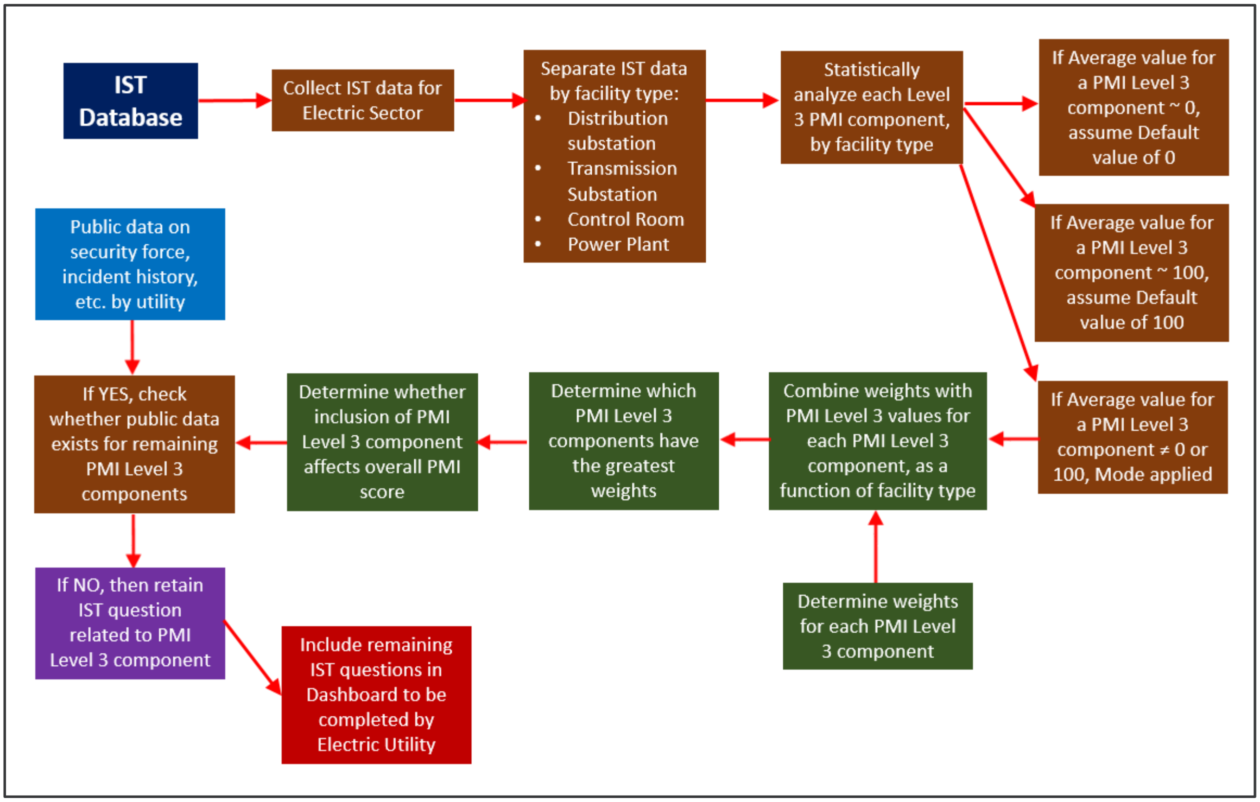

Figure 8.3. Overall process diagram for revising the DHS PMI (based on IST questions) for the electric sector.

The PMI organizes the information collected with the IST into four levels of information in order of increasing specificity; raw data are gathered at Level 4. These are then combined further through Levels 3, 2, and, finally to Level 1. Each of the Level 1 components is defined by the aggregation of Level 2 subcomponents that allow analysts to characterize aspects of a facility's existing security posture. The PMI is constituted by five Level 1 components, 25 Level 2 subcomponents, and 64 Level 3 subcomponents. For the PMI, the information collected characterizes the weakest protective measures (i.e., the weakest portion of fence if types and characteristics vary). Some of these values can be inferred from current industry practice (NERC and similar standards) for elements such as "Physical Security", for which the Level 2 subcomponents are shown below Figure 8.4. In this figure, the Level 1 component is "Physical Security", the nine Level 2 components are shown in the middle orange-colored boxes and include "Fences" to "Building Envelope." The Level 3 components for the Level 1 "Physical Security" are shown on the right-hand side of Figure 8.3 and include "Type" (off of fences) to "Facility Access." The Level 3 subcomponents provide more granular information concerning the Level 2 subcomponents, which are aggregated into the Level 1 "Physical Security" component.

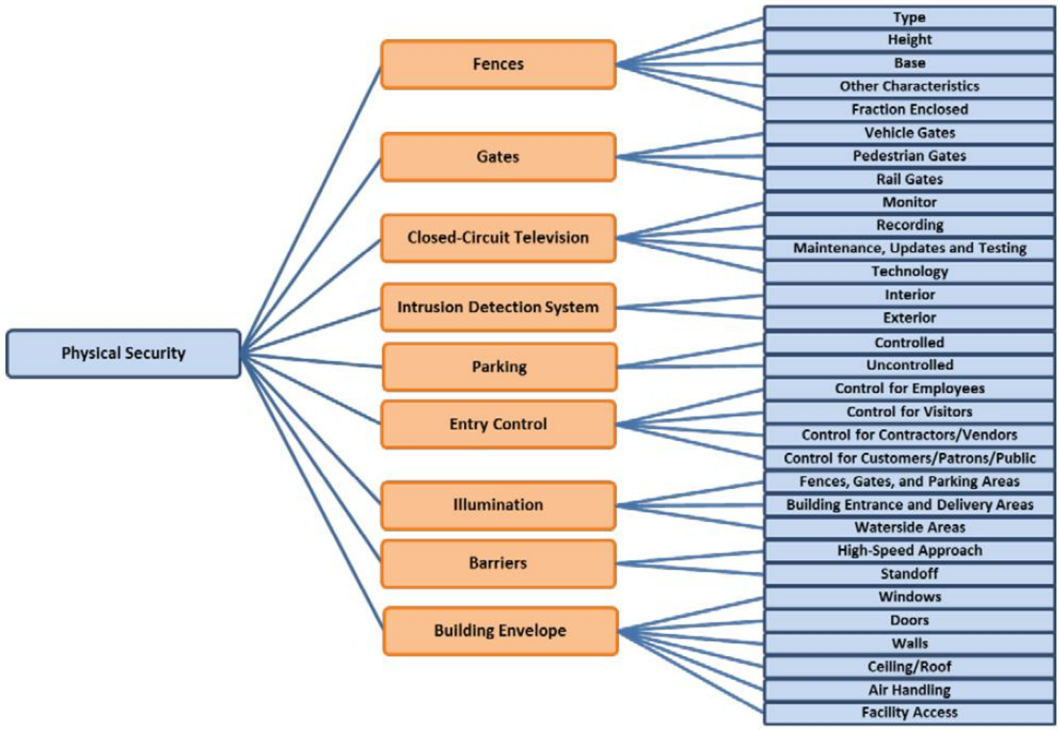

Figure 8.4. Level 2 and Level 3 subcomponents for Level 1 "Physical Security" component (Argonne 2013).

The PMI requires information that may not be available from public data sources, such as Memoranda of Understanding/Memoranda of Agreement (MOUs/MOAs) with local law enforcement, and detailed characteristics of utility security forces. These gaps may be supplemented by analysis performed by Argonne National Laboratory (Argonne) to identify gaps in preparedness and rapid recovery measures for DOE's QER, which used data collected on 170 electric facilities from January 2011 through September 2014 (DOE 2015c). Another option being investigated is whether default values could be applied based on statistical analysis of the PMI Level 3 components, which could be subsequently revised when site- or utility-specific data become available. This approach may be applicable for Level 1 Security Force component and its Level 2 and Level 3 subcomponents, which are shown in Figure 8.5. Public information is available for the Level 2 subcomponent "Staffing" in Figure 8.5 while default values for Level 3 subcomponents such as "Programs" and "Frequency" (associated with security force training) can be assumed based on current electric industry security guidance (e.g., NERC 2011).

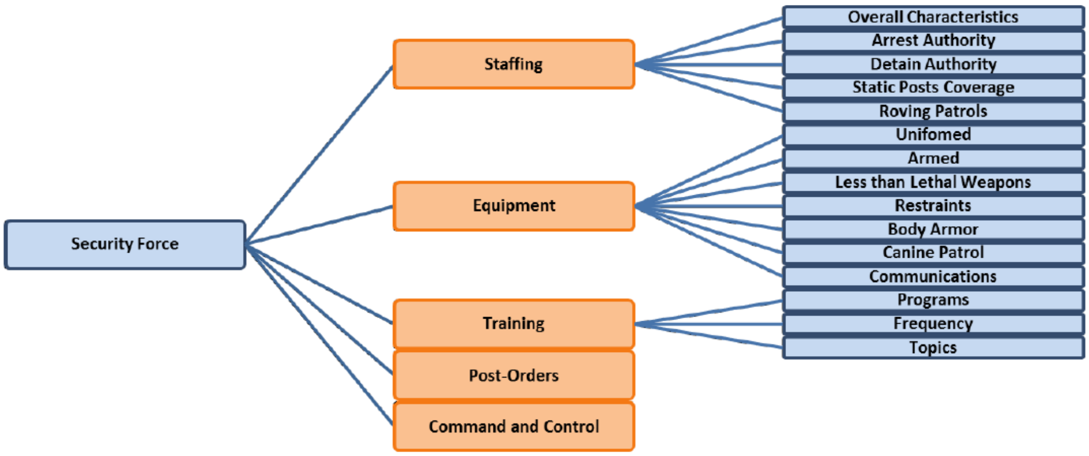

Figure 8.5. Level 2 and Level 3 subcomponents for Level 1 component "Security Force" (Argonne 2013).

Information needed for the Level 1 Security Activity History/Background component may be available from data collected by various organizations concerning electric outages in the United States. The Level 2 subcomponents (the two orange-colored boxes) and the ten Level 3 subcomponents (ranging from "Prior Vulnerability Assessment Conducted" to "Initiation of Planning and Preparedness") are shown in Figure 8.6.

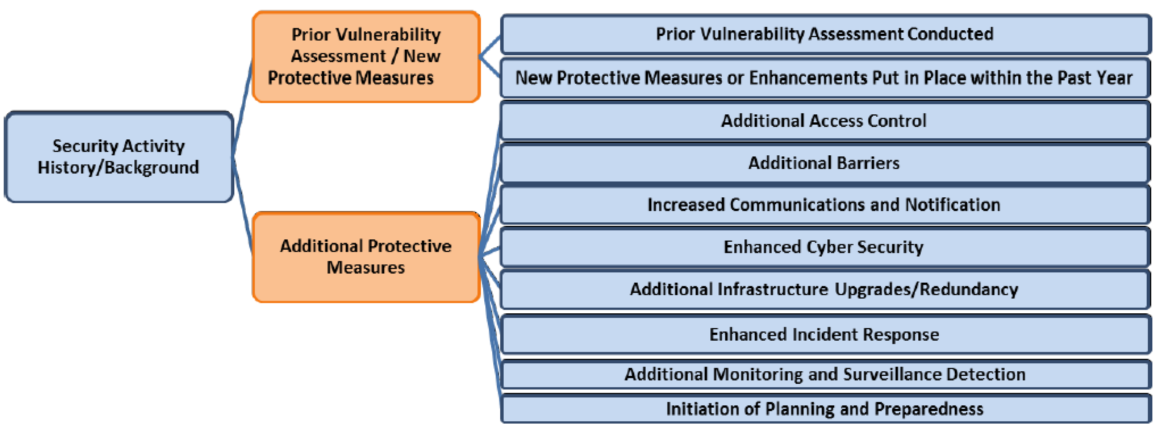

Figure 8.6. Level 2 and Level 3 subcomponents for Level 1 "Security Activity History/Background" component (Argonne 2013).

Another sub-option shown in Figure 8.3 would be to reduce the number of questions in the analysis, based on the statistical analysis of the PMI Level 3 components, which may result in a model similar to the Rapid Infrastructure Survey Tool [RIST] (Figure 8.7; NASEO 2014). The Rapid Infrastructure Assessment captures a facility's physical and operational security and resilience data. The data are then analyzed to determine the facility's relative security and resilience in comparison to the national average for similar facilities. This approach would have to be researched to determine its applicability for establishing the security posture of a given electric utility using publicly accessible data; an initial assessment indicates that the questions in the RIST would require utility input. Though the questions are similar to those in the IST, the methodology for the calculations is different, which creates uncertainty regarding the relationship between the indices provided via the RIST aligning with the indices provided via the IST.

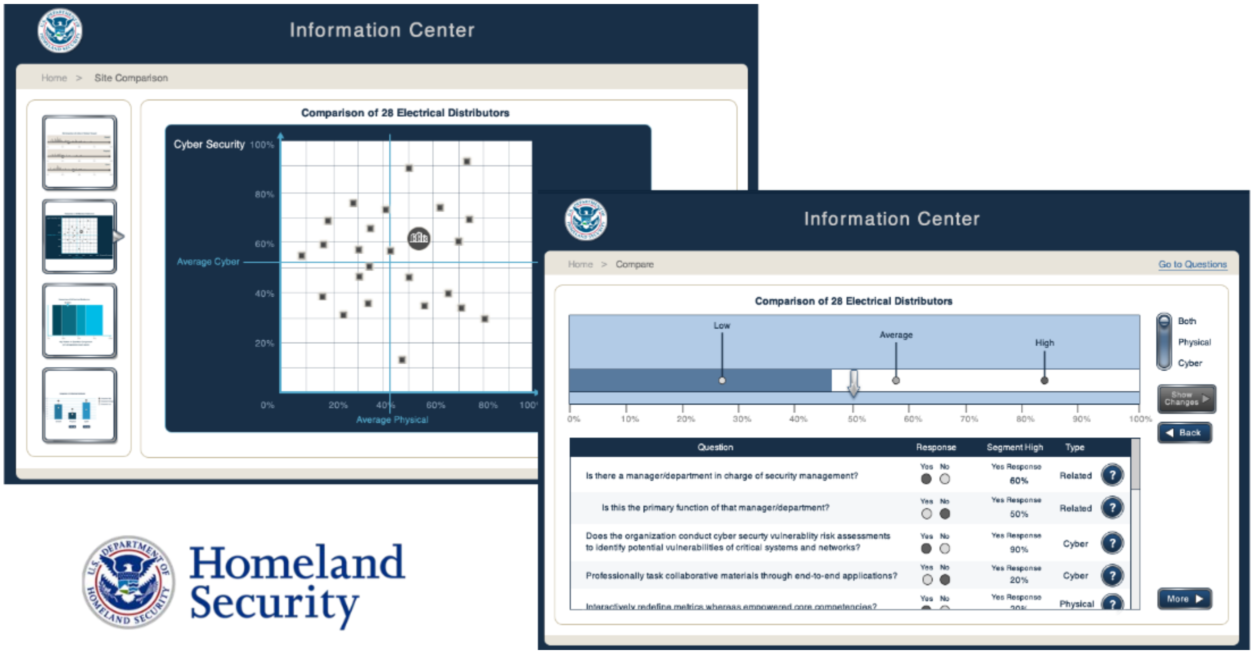

Figure 8.7. Sample information from the Rapid Infrastructure Survey Tool (Norman 2015).

The above approach was presented to and discussed with a number of potential stakeholders during 2016, and the following points were made:

- Argonne received approval from DHS management to develop potential metrics for physical security based on the DHS PMI:
  - DHS agreed to support GMLC activity through development of default values (for sub-metrics) and identification of which sub-metrics are most significant in determining physical security of the electric sector.
  - Some PMI default values have been received from DHS, and statistical analysis of the DHS IST data set for the electric sector is under way.
- EPRI agreed to review the proposed approach and provide suggestions for improvement.
- EEI stated that it would be willing to present the proposed physical security metrics to its members for their approval and guidance if and when a demo tool (showing how the overall PMI is calculated for a given electric utility) has been developed.
- The National Association of State Energy Officials (NASEO) stated that it would review the proposed approach to determine its acceptance by state PUCs and agencies, and establish which states/regions may be most willing to participate in a pilot program.
- The above organizations stated that they would be willing to be involved in the development of cyber security metrics for the electric sector during fiscal year 2017.

8.4.2 National Infrastructure Protection Plan Security Metrics

8.4.2.1 Potential or Proposed Approach

For development of future security metrics, another option could be to follow the approach taken in the National Infrastructure Protection Plan (NIPP), which defined three sets of primary measures as follows (DHS 2009):

- Descriptive measures, which will be used to understand electric resources and activities. These measures will be qualitative in value, and should be the easiest and least costly for which to collect data.
- Process (or output) measures, which show progress toward achieving security goals. The data for these measures would be quantitative or semi-quantitative in value.
- Outcome measures that track the progress toward a strategic goal by beneficial results rather than level of activity. These outcome measures, unlike descriptive and process measures, are generally determined by models, assumptions, or complex formulas.

Example metrics for the energy sector used in the NIPP are shown in Figure 8.8. This approach was rejected for physical security metrics development because it requires detailed utility input into decision metrics such as how well does the utility "Assess Risks" or "Set Security Goals."

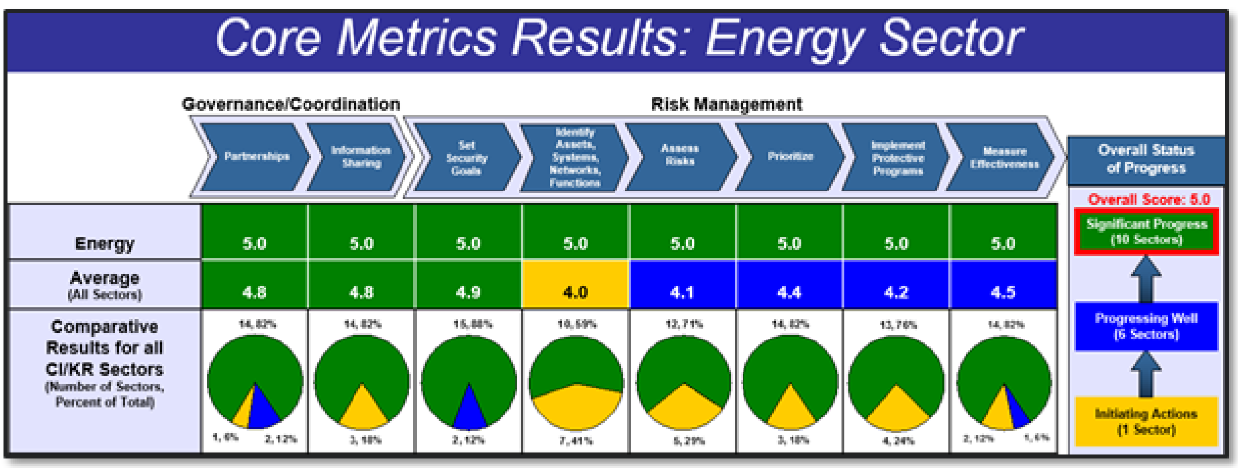

Figure 8.8. Core metrics results for the energy sector in the NIPP (DHS 2009).

8.5 Challenges

Some security data are available on a national level for the electric sector, but there is no single data set derived from decades of data collection that can tell precisely what adversaries will do, how often they will do it, and how much it will cost the electric sector when they do it. Due to their sensitive nature, security data collected by the individual utilities are not publicly available.

Data that are publicly available for use in security metrics include the following:

- Historical data on electric outages due to vandalism, sabotage, and cyber incidents from Eaton's Blackout Tracker (Eaton 2016) and DOE Form OE-417 (DOE 2016b);
- U.S. Bureau of Justice crime statistics on property crime and burglary (DOJ 2016);

- U.S. Bureau of Labor Statistics data on the number of security guards at the state level, with potential for more location-granular data (DOL 2016); and
- DHS ECIP data analysis for the 2015 DOE QER, which identified gaps in preparedness and rapid recovery measures for surveyed energy facilities and identified gaps in preparedness and rapid recovery measures for 273 surveyed energy facilities (DOE 2015b).

Discussions will be held with energy sector contacts to attempt to specify the source of the data needed for each proposed security metric, the frequency of data collection, and the spatial characteristics (national versus regional, state, utility, etc.). It will also be established who is responsible for raw data accuracy, data compilation into measurements, and calculation of each security metric.

The outcome of first-year activities would be the complete development of this approach to revise the PMI using a revised version of the IST specific to the electric sector, including public data sets and default values for required inputs, which can be modified by electric utilities using site-specific information.

The vision for Years 2 and 3 would be the development of a spreadsheet or potentially a Web-based dashboard tool that could be publicly provided to the electric sector (Year 2) and development of cyber security metrics and data (Years 2 and 3). Figure 8.9 shows an example dashboard showing physical security metrics.

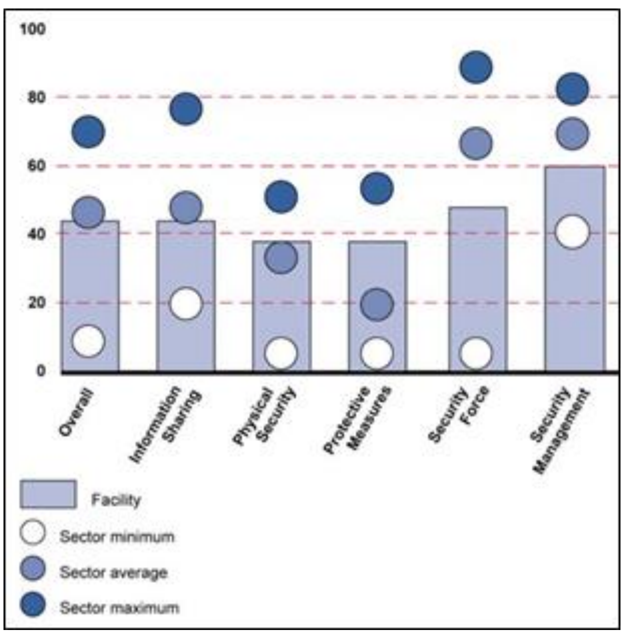

Figure 8.9. Example dashboard for physical security metrics.

8.6 Scope of Applicability

The primary users of this proposed approach for physical security metrics (the development of cyber security metrics will be addressed in the next phase of this project) would be:

- utilities (for self-assessment), and
- State PUCs (to assess the security posture of local utilities). It should be noted that the development of state-level security metrics needs to be discussed further with the electric sector. There is generally

a reluctance by electric utilities to share physical security information because of the inherent nature of the topic (i.e., making an electric utility more vulnerable to attack by giving out intelligence about its systems, weaknesses, monitoring methods, etc.). This may limit the potential application of the proposed approach to develop state-level security metrics scores.

8.6.1 Asset, Distribution, and Bulk Power Level

The PMI approach starts at the asset level and determines the PMI score for key assets such as substations, control centers, and electric generation facilities.[1] The PMI approach was selected for physical security metrics development because a version of these metrics has been applied by DHS to over 400 electric assets. The application of the PMI approach would address the lack of consistent information about the security posture of the electric sector.

The process described in Figure 8.3 will produce a revised PMI, specifically tailored towards electric sector infrastructure. Electric utilities that have not had DHS personnel conduct an IST survey could answer a select set of questions that would provide insight into their existing security posture. The revised set of questions will contain default values that would be determined using statistical analysis of the available IST data for electric-sector components or publically available data. The utility can then change those defaults and add additional information specific to their utility to get tailored PMI values for t heir assets, considering their threat environment.

Recall from the previous section that the PMI is constituted by five Level 1 components, 25 Level 2 subcomponents, and 64 Level 3 subcomponents. Figure 8.10 provides a typical IST dashboard showing calculated overall PMI and its five sub-metrics. The proposed approach is to develop a similar PMI dashboard for electric-sector components that would focus on the five Level 1 components using IST answers to developed default values and/or public data sets.

[1] The NERC CIP-002 standard describes how utilities define critical assets, as well as critical "cyber" assets. Essentially, all bulk transmission assets are deemed critical, and utilities may designate additional assets as critical based on other factors. The first requirement under the CIP 014 standard is for utilities to identify transmission stations, substations, and control centers that—if rendered inoperable or severely damaged—could result in widespread instability, uncontrolled separation, or cascading failures within an interconnection.

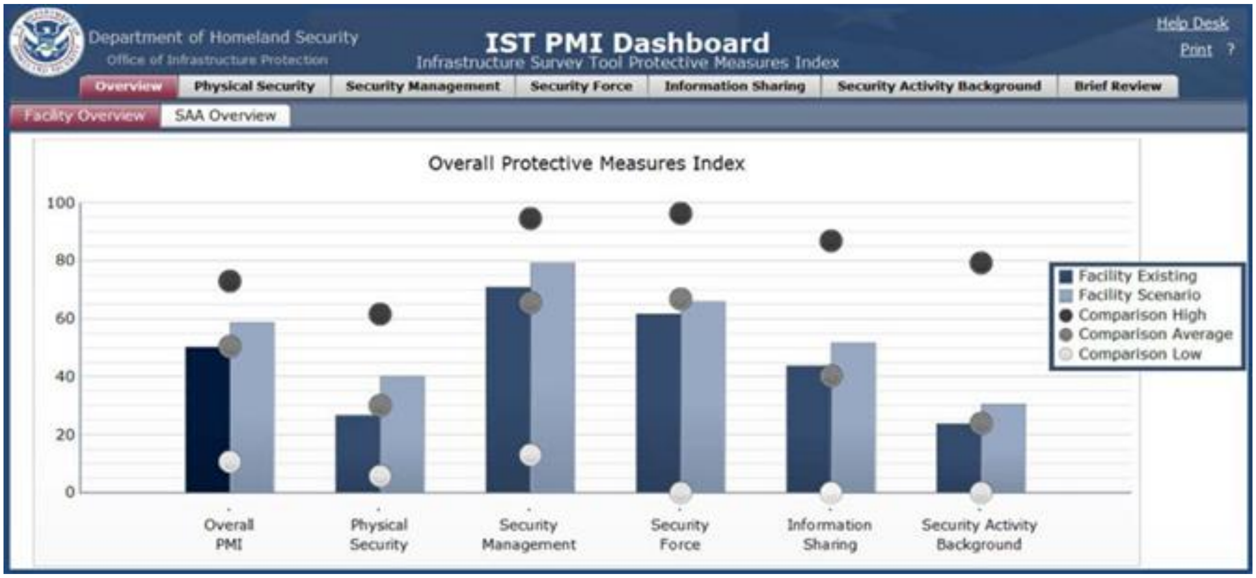

Figure 8.10. IST dashboard showing calculated PMI and its five sub-metrics.

For the PMI, the information collected characterizes the weakest protective measures (i.e., the weakest portion of fence if types and characteristics vary). Some of these values can be inferred from current industry practice (NERC and similar standards). IST summary information for typical electric-sector responses, as provided by DHS, indicates that almost all electric substations have performed background checks, and contain fencing and gates, etc. as shown in Figure 8.11 and Figure 8.12.

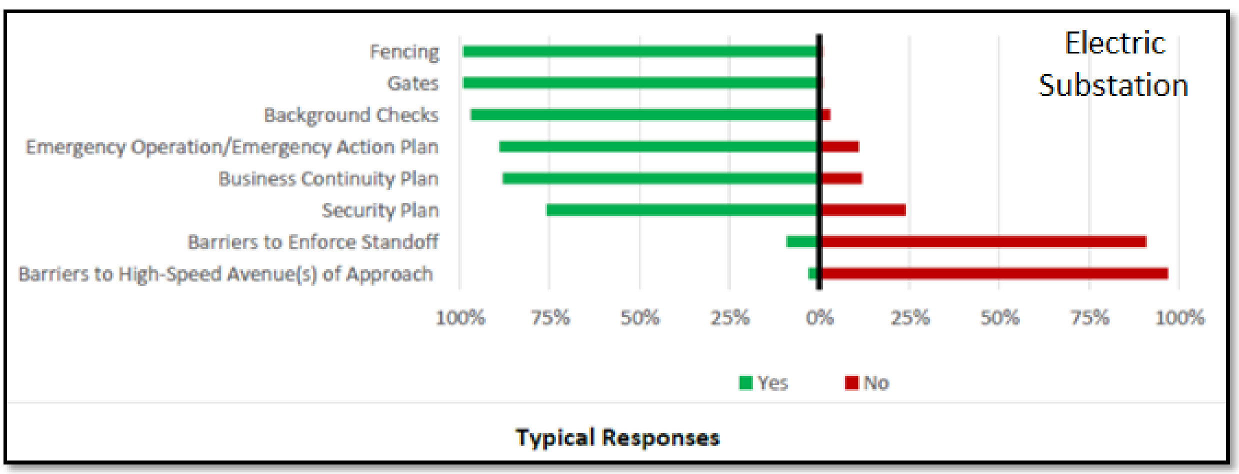

Figure 8.11. Typical responses to IST questions for electric substations.

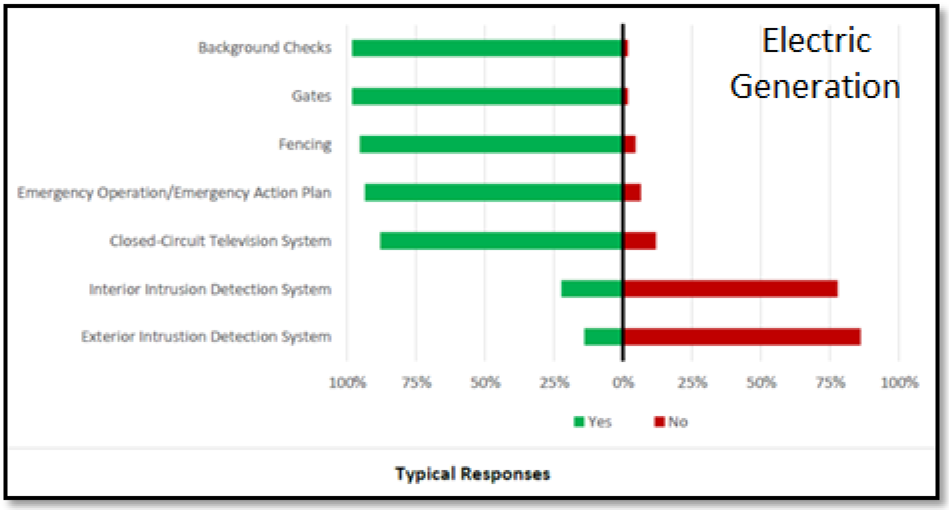

Figure 8.12. Typical responses to IST questions for electric generation plants.

The PMI requires information that may not be available from public data sources, such as MOUs/MOAs with local law enforcement and the characteristics of security forces. These gaps in publicly available data would be supplemented by analysis previously performed by Argonne to identify gaps in preparedness and rapid recovery measures for the QER using data collected for 170 electric facilities from January 2011 through September 2014 (DOE 2015d). The electric facilities considered in the previous Argonne analysis included transmission and distribution substations as well as control rooms and power plants, which are identified in the NERC CIP 014 standard as key physical assets and may be part of an utility's critical facility list (Shumard and Schneider 2014).

It can be expected that the current physical security posture of a given electric utility may depend on

- historical crime statistics,
- urban vs. suburban vs. rural locations of critical electric assets,
- prior incidents of vandalism and sabotage, and
- instances of copper theft, etc.

It is well known that substation design differs depending on its location; enclosed substations in urban areas typically are located within buildings (Figure 8.13), while open-air substations in rural areas are built without any secondary enclosure (Figure 8.14). The existence of any secondary enclosures such as buildings is a major physical security benefit that would be reflected in the PMI score for enclosed substations.

Figure 8.13. An enclosed substation (note indoor design blends in with its surroundings).

Figure 8.14. An open-air substation (note absence of secondary containment).

The proposed approach will investigate whether PMI scores for electric utilities correlate with historical crime statistics, prior incidents of vandalism and sabotage, and other physical security-related issues. The analysis will be limited to those electric sector facilities for which DHS IST data are readily available (over 400 electric assets).

8.6.2 Utility Level

Overall PMI for a given electric utility would be the weighted sum of the PMIs for expensive hard-to-replace assets, such as substations, power plants, and control rooms, consistent with the approach in the NERC CIP 014 Standard for Physical Security. The approach would ignore assets such as transmission towers, which can be quickly and easily replaced and are assumed to be not as critical as long-lead–time equipment such as transformers in substations, etc.

The overall PMI for an electric utility would account for the PMI scores of its critical assets, which are assumed to include the utility control center(s), distribution and transmission substations, and electric generation plants:

$$(PMI)_{utility} = \sum (n_j * IF_j * PMI_j) / \sum (n_j)$$

where

(PMI)utility = the composite PMI score for the electric utility;
ni = the number of assets of category "i";
IFi = the importance factor of asset category "i" [an IF of 1 would mean all assets are equally important];
PMIi = the PMI score for asset category "i".

Information about the number and characteristics of each utility's control center(s), distribution and transmission substations, and electric generation plants would be collected from the following sources:

- electric utility control center data based on the location of the electric utility headquarters
- electric substation data from Platts Electric Substation geospatial data layer[1]
- electric generation plant data from the EIA-860, Annual Electric Generator Report, EIA-860M, Monthly Update to the Annual Electric Generator Report and EIA-923, Power Plant Operations Report.[2]

8.6.3 State Level

One potential approach to determining the overall PMI for a state would involve the PMI scores for the electric utilities located within the state, normalized by the number of electric utility customers:

$$(PMI)_{state} = \sum \{ (PMI)_{utility} * n_{customers} \} / \sum (n_{customers})$$

where $(PMI)_{state}$ is the composite PMI score for the electric utility sector in the state, and $n_{customers}$ is the number of electric customers by utility in the state, as provided by EIA forms EIA-861- schedules 4A & 4D and EIA-861S.[3]

Other approaches exist for determining the overall PMI for a State based on the PMI for each electric utility, such as normalizing using

- the total capacity of each electric utility, as provided in Form EIA-826[4];
- the total number of electric assets for each electric utility, as provided by EIA;
- the total revenue of each electric utility, as provided by EIA forms EIA-861- schedules 4A & 4D and EIA-861S;[5] and

[1] Platts, undated. *Electric Substations Metadata – Platts*, available at http://www.platts.com/IM.Platts.Content/ProductsServices/Products/gismetadata/substatn.pdf, accessed January 25, 2017.

[2] EIA, 2017. "Layer Information for Interactive State Maps – Power Plants," available at http://www.eia.gov/maps/map_data/PowerPlants_US_EIA.zip, accessed January 25, 2017.

[3] EIA, 2017. "2015 Utility Bundled Retail Sales- Total," available at http://www.eia.gov/electricity/sales_revenue_price/xls/table10.xlsx, accessed January 25, 2017.

[4] EIA (Energy Information Administration). 2017. "Form EIA-826 detailed data," available at http://www.eia.gov/electricity/data/eia826/, accessed January 25, 2017. s

[5] EIA (Energy Information Administration). 2017. "2015 Utility Bundled Retail Sales- Total," available at http://www.eia.gov/electricity/sales_revenue_price/xls/table10.xlsx, accessed January 25, 2017.

- the number of critical sites such as healthcare facilities (hospitals and senior care centers), first responder (police and fire) stations, mass transit facilities, data centers, and wastewater treatment plants (WWTPs).[1]

The most appropriate way to combine individual PMI scores for each electric utility into a composite PMI score for the electric sector in a state would be determined through consultation with electric-sector subject matter experts. Preferences for the specific values for these weights will be determined via a formal elicitation process and would account for factors such as variations in facility vulnerability between electric utilities. Sensitivity analysis would be performed to determine whether the weights are reasonable.

8.6.4 Regional Level

The proposed approach to determining the overall PMI at the regional level would involve the PMI scores for the electric utilities located within the region, similar to the approach proposed at the state level.

8.6.5 National Level

The proposed approach to determining the overall PMI at the national level would involve the PMI scores for the electric utilities located within the nation, similar to the approach proposed at the state level.

8.6.6 Other Level

The approach at this level is yet to be determined.

8.7 Use-Cases for Metrics

8.7.1 Smart Reconfiguration of Idaho Falls Power Distribution Network for Enhanced Quality of Service

The objective of the GMLC project titled "Smart Reconfiguration of Idaho Falls Power Distribution Network for Enhanced Quality of Service" is to identify existing technology and integration solutions/methods that could be applied to the Idaho Falls utility system, which relies on significant amounts of imported power to keep as much of the system operating as possible during system events at both the transmission and distribution levels. Improving physical security at Idaho Falls substations is something that is specifically called out (although with a focus on reducing the impact of any incidents via smart system design, e.g., islanding). There may be potential to apply the PMI demo tool under development to estimate the composite PMI score for the Idaho Falls utility system, to more broadly understand the current physical security state and how proposed actions might improve it.

The physical security metrics team has contacted the GMLC project lead for the Idaho Falls GMLC activity to understand how the work being performed compares to what was originally scoped, including

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[1] FEMA (Federal Emergency Management Agency). 2013. *Performance of Critical Facilities and Key Assets*, available at https://www.fema.gov/media-library-data/1385587199555-ebd60a9506168b4fd5a79ee519520c1e/Sandy_MAT_Ch5_508post.pdf, accessed on March 18, 2017.

physical security, and whether there is interest in examining the physical security opportunity for the Idaho Falls utility system in greater depth.

8.7.2 Commonwealth Edison

Exploratory discussions are under way with security personnel at Commonwealth Edison (ComEd), which is the largest electric utility in Illinois and serves the Chicago and Northern Illinois area. ComEd provides electric service to more than 3.8 million customers across Northern Illinois and its service territory contains urban, suburban, and rural customers. It also contains transmission (69 to 765 kV), subtransmission (34.5 kV), and distribution (4.16 to 13.8 kV) substations.

This proposed use-case would provide a spreadsheet or potentially a Web-based dashboard tool that would contain electric facility data specific to ComEd and estimate the individual Level 1 and 2 components for review and comments. Discussions between Argonne and ComEd security personnel are anticipated and would result in determining the appropriate normalization method and importance factors specific to substations, control centers, and generating plants. The final outcome would be utility validation of the PMI approach for the electric sector, including assumptions, data, and default values.

8.8 Value of Metrics

Based on engagements with stakeholders, the following specific values were reported:

- The DHS IP Assessments Team from the DHS Office of Infrastructure Protection (IP) stated that DOE's "grid security metrics efforts" are "examples of opportunities for DHS IP assessments to contribute to DOE efforts."
- In an initial discussion describing the methodology, NARUC staff indicated that such a comparative scale could be useful to provide utility commissions with an understanding of the relative physical security posture of the utilities within their jurisdictions, and the relative impact of potential investments designed to improve physical security, without requiring the utilities to share potentially sensitive data. A follow-up engagement with NARUC's critical infrastructure resources staff subcommittee is being planned.

8.9 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 sustainability 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 DHS, EEI, EPRI, and NASEO. The following is a synopsis of the key points made during the 1.5 hour briefing:

- Technical considerations:
  - The aggregation of multiple indicators representing detailed information about the security posture may not be meaningful because an aggregated indicator masks the higher detailed information. It was suggested to present both the sub-indicators that make up the PMI as well as the PMI

- One reviewer suggested providing as much transparency as possible about the underlying assumptions of security measures that were considered in the formulation of the approach and tool development.

- Value of work – Reviewers generally saw that the approach could provide value to an electric utility and regulators and state energy offices in the following respects:
  - The metrics approach was viewed as useful for utilities to understand better the relative strength of their physical security posture as well as how they compare against peers.
  - The metric approach could be useful for identifying strategies to improve specific physical security practices within their organization.
  - Information derived from the developed approach could be useful for informing rate-recovery decisions with or without consideration of the peer comparisons.
  - General concern was expressed about the appropriateness of using the method for peer comparison or even presenting geographically aggregated protected measures index values. This concern in part stemmed from prior experience where some reviewers have seen metrics for other projects be used to create unfair judgments among and between entities that could lead to inappropriate policies.
  - The reviewers also recognized challenges associated with protecting the electric utility-completed data.

9.0 Baselining Year 1 Metrics

This section addresses the question of how the proposed metrics that currently do not exist can be baselined. (Note that this does not apply to the existing metrics, such as GHG emissions). By baselining, we mean how the metrics can be calculated or measured to assume their first estimation that is considered a basis or reference, either for the next year's estimation or to be estimated for a different asset or utility organization; thus establishing a basis or baseline for the metrics.

One of the main objectives of this effort is to provide a quantitative framework for measuring the progress of grid modernization in various regions of the country. The metric categories were in part selected by DOE to provide a balanced view of the state of the grid at any point in time, recognizing that tradeoffs between categories could occur as modernization investments are made. For example, the implementation of investments that target improved system flexibility could also benefit grid reliability and resilience, could improve environmental sustainability through supporting increased adoption of variable clean generation technologies, but might require increased cost to customers in the near-term. Measuring grid modernization progress can be considered from several different activity perspectives:

- The impact of completed Grid Modernization Initiative research, development, demonstration, and deployment (RD^3) program activities on the pace and scale of the modernization of the U.S. grid over time.
- The impact of a specific investment related to a technology demonstration project or a production implementation by a utility, ISO/RTOs, or other market participant, or of a specific legislative or regulatory policy, or market mechanism, on the specific targeted geographic area in which the project occurs or the policy or mechanism is meant to affect.
- The overall impact of the total portfolio of grid modernization activities, both in terms of the evolving technology make-up of the grid (including its generation mix) and the policy and regulatory context that influences both the deployment of technologies on the grid and the constraints under which the grid can be operated.

In addition, progress for each of these perspectives can be measured from different time considerations:

- Prospectively: The future impact of the activity can be estimated prior to its actual completion or implementation on the grid. In some cases, these impacts can be expressed as projected costs and benefits and included in the analysis that informs a decision to proceed with the activities.
- Retrospectively: The impact of the activity can be assessed after its actual implementation, either through application of formal evaluation methods or through ongoing data collection and reporting efforts.

For any of the activity perspectives, and for either time consideration, determination of the impact of an activity is often made by comparing two grid states or scenarios:

- The state of the current or expected grid prior to or without the implementation of the activity
- The actual or expected state of the grid after or with the implementation of the activity

The difference between the two states is then a measure of impact of the activity on the grid. The first of these states is often referred to as a baseline. In the case of a retrospective impact analysis, the baseline consists of actual measured attributes of then current state of the grid (e.g., historical time series at some time interval). For a prospective analysis, the baseline often takes the form of a "business as usual" projection, usually modeled, of what might be expected to occur going forward without the activity occurring.

This effort is intended to formalize specific metrics in each of the six attribute categories. These formalized metrics are not meant to represent a complete set of metrics that might be necessary to inform a broad understanding of impacts within each category (e.g., see Appendix A for an inventory of potentially useful metrics for each attribute category, most of which are currently reported for at least some geography within the United States). The metrics being formalized are appropriate for application to only the latter two activity perspectives identified above.[1] Depending on the attribute category, the formalized metrics may be suitable for application to one or both time considerations. As such, the type of baseline appropriate for each category varies.[2]

Table 9.1 summarizes the applicable baseline(s) by metric or metrics class for each category, and the status and potential geographic scope of the documentation of such a baseline. This baseline characterization is informed significantly by stakeholder feedback on the applicable use of the metrics. Following the table, a brief context is provided for each of the categories.

1 The attribution of impacts to specific sources of investment, particularly in research, development, and demonstration, is a challenging exercise typically approached in retrospective evaluation studies. DOE has a rich experience assessing its RD[3] activities in this manner (for more information, see https://energy.gov/eere/analysis/program-evaluation). The National Academies has also conducted retrospective assessments, including for specific DOE energy programs (see https://www.nap.edu/catalog/10165/energy-research-at-doe-was-it-worth-it-energy-efficiency). This type of application of grid-related metrics falls outside the scope of this work effort.

2 Those metrics being formulated in this work effort that have prospective application are informing the development of a Grid Services and Technologies Valuation Framework in GMLC 1.2.4.

Table 9.1. Ability to baseline Year 1 metrics by metrics area.

Metrics Category	Baseline Feasibility for Metrics Formalized in Year 1 — Retrospective	Baseline Feasibility for Metrics Formalized in Year 1 — Prospective	Status/Plans
Reliability	Distribution – yes Bulk power – yes Probabilistic transmission planning – no	Distribution – no Bulk power – no Probabilistic transmission planning – yes, but would limited to a "business as usual" comparator to a specific investment	Metrics have not developed fully. Baseline development will be considered in Years 2-3, but is likely to be limited to specific geographic area(s).
Resilience	For direct and indirect consequence metrics: Electrical service- no Critical electrical service - no Restoration - no Monetary - no Community function - no Retrospective baseline development is hampered by lack of available historical data, particularly in relating outage-related data to specific hazards.	For direct consequence metrics - yes, but would be limited to a "business as usual" comparator to a specific hazard and type of infrastructure.	Prospective baseline development is planned in Years 2-3 for the pilot case study.
Flexibility	Flexibility demand – yes Flexibility supply - yes Flexibility market balance - yes	Flexibility demand – yes Flexibility supply - yes Flexibility market balance - yes Prospective baseline development would be limited to a "business as usual" comparator to a specific investment, policy, or market mechanism.	While development of a retrospective baseline is feasible, significant effort is required to isolate flexibility-related events from other system or market-related conditions. Stakeholders have also indicated that prospective baselines associated with potential investment decisions are more valuable. Retrospective and prospective baseline development is planned in Years 2-3 for the pilot case study.

Table 9.1. (contd)

Metrics Category	Baseline Feasibility for Metrics Formalized in Year 1 – Retrospective	Baseline Feasibility for Metrics Formalized in Year 1 – Prospective	Status/Plans
Sustainability	CO_2 Emissions – yes	CO_2 Emissions – yes A prospective baseline could be generated for a recognized national baseline electric sector projection (e.g., EIA's Annual Energy Outlook Reference Case) or as a "business as usual" comparator to a specific investment, policy, or market mechanism.	Retrospective baselines at the federal level for the national data products examined are included in this report. These baselines do have some gaps or limitations, mostly notably the lack of inclusion of generation sources < 1 MW in capacity. There are no further plans in Year 2-3 to develop more geographically granular retrospective baselines (although this would be straightforward) or to pilot a prospective baseline for a specific case study for CO_2 emissions. Year 2-3 effort is proposed to focus on development of a Water Risk Metric that assesses water use in the context of its availability (in space and time). This metric could have retrospective and prospective components, including use case pilot application.
Affordability	For the residential end-use sector: Average customer cost burden – yes Affordability gap factor – yes Affordability gap headcount – yes Affordability gap index – yes Affordability gap headcount index – yes	For the residential end-use sector: Average customer cost burden – no Affordability gap factor – no Affordability gap headcount – no Affordability gap index – no Affordability gap headcount index – no Prospective baseline development is limited by the difficulty of meaningfully projecting household income.	Retrospective baselines at the national and state level are included in this report on an annual time step based on public data sources. County, service territory, and local examples are also provided for California and Alaska. The latter example uses stakeholder supplied customer cost data. Year 2-3 plans include a more detailed pilot application to a utility service area based on utility-provided customer bill data, and examination of the applicability to nonresidential customer classes.
Security	Physical security index metrics - yes, but only based on public information and default values derived from DHS critical infrastructure database	Physical security index metrics - yes, but would be limited to a "business as usual" comparator to a specific investment or policy	Some stakeholders did not consider retrospective baselines crossing utility service territories (e.g., at state or national level) as being useful and expressed concern over potential mis-use. Prospective baseline development is planned in Years 2-3 for the pilot utility case study.

9.1 Reliability

Two of the three classes of metrics under development (distribution and bulk power system metrics) are related to historical data and lend themselves to retrospective analysis. As these metrics are still being formalized, pilot baselines are expected to be generated for specific geographic regions as a part of Year 2-3 activities.

The third class of metrics, for probabilistic bulk system planning, is by design leading in nature and can inform prospective decisions on transmission. Simulation-based modeling methods will be employed to conduct probabilistic contingency analysis involving variable renewable generation to develop these metrics. Prospective baseline development would involve simulating the contingencies if no change is made to the transmission system. This "business as usual" baseline would then be compared to a set of simulations where a proposed change is made to the bulk system. As these metrics are still being formalized, pilot prospective baselines are expected to be generated for a specific geographic region as a part of Year 2-3 activities as part of a collaboration with a utility or RTO.

9.2 Resilience

Stakeholders confirm that resilience metrics formalized in this work effort are most effectively applied in forward-looking (prospective) analysis focused on specific types of hazard events, rather than retrospectively based on historical data that is available. Retrospective baseline development is hampered by lack of available historical data, particularly in relating outage-related data to specific types of hazards.

Prospective baseline development would involve modeling the impact of a set of future events if no change is made to the electric infrastructure of interest. For the consequence metrics of interest, the baseline is based on a modeled set of simulations that typically estimates the consequences of the set future events with "business as usual" assumptions. This "business as usual" baseline would then be compared to a modeled set of simulations where a proposed set of actions or investments is made.

9.3 Flexibility

Historical data from CAISO archives can be used to develop a retrospective baseline to assess current system flexibility for this pilot test area, relying on reports in press related to flexibility. For example, wind and solar curtailment metrics can be baselined to assess current flexibility of the system. The challenge is to differentiate between curtailments due to contingencies such as generator or transmission line forced outages and curtailments due to insufficient ramping capabilities or unit commitment and dispatch logic that do not position units to provide sufficient flexibility. We plan to work with stakeholders to identify the frequency and magnitude of these conditions in the historical data and summarize general trends. Similar baselines for other metrics described in the Reference Document can also be developed.

Prospective baseline development is also planned for the CAISO pilot, again relying on reports in press related to flexibility in that region. The prospective baseline would be based on production cost model outputs for a scenario of "business as usual" assumptions. This "business as usual" baseline would then be compared to a modeled simulation where a proposed policy, investment, or market mechanism is implemented.

9.4 Sustainability

Year 1's effort examined national data products provided by EPA and EIA related to electric sector GHG emissions. Retrospective baselines at the national level for 6 of the 8 national data products examined are included in this report for years 2008 - 2014. These baselines do have some gaps or limitations, mostly notably the lack of inclusion of generation sources < 1 MW in capacity. Two additional data products provide forward-looking views of CO_2 emissions based on projections of generation mix and associated fuel consumption and could be considered forms on "business as usual" baselines (not included in this report). While several recent studies have documented and applied a consistent prospective method, such prospective application is not included in the scope of this work effort.

For Years 2-3, a Water Risk Metric is proposed to be developed that relates water use by electricity generation to water availability. This new metric will have prospective and retrospective aspects that could be developed and applied in a pilot use case.

9.5 Affordability

The formulation of the residential customer cost burden metrics developed in Year 1, and the supporting customer electricity cost and income data needed to calculate the metrics, lend themselves to the development of a retrospective, as opposed to a prospective, baseline. Several examples of such a baseline for multiple years are included in this report based on publically reported data, including at state and national levels. Some stakeholders indicated that such a time trend analysis is very useful to assess the changes over time for a specific utility service territory and felt that this is a more appropriate application of the formulated metrics than a comparison across geographic areas that could have different energy consumption patterns.

9.6 Security

It is possible to develop a national retrospective baseline for the physical security index metrics formalized in this effort based solely on public datasets on the number of electric sector facilities, which electric sector facilities have an on-site staff, which utilities have a security force, and others, along with electric sector-level default values derived from the DHS critical infrastructure database. However, this baseline may not reflect current electric sector operations due to the reliance on historical data (perhaps two or more years old). A much-higher confidence level would be achieved through direct involvement by electric utilities in adjusting the default values and public data to match their current operations. However, some stakeholders indicated that it could be challenging to recruit electric utilities to update the physical security metrics and provide the results to a third party for synthesis, given the sensitivity associated with some of this information.

This utility-specific information could be more forthcoming as a part of a prospective analysis that compares a "business as usual" baseline to the revised index after a specific security investment within a utility service territory is made or a policy is implemented.

10.0 Using Multiple Metrics to Inform Decision-Making

The aforementioned metrics are intended to provide crucial information to stakeholders for enhancing their decision-making processes with respect to modernization of the electric grid. The categories of metrics (reliability, affordability, resilience, sustainability, flexibility and security) are the means by which to measure progress toward modernization. The decision space in which stakeholders operate is highly complex and requires consideration of multiple, sometimes conflicting, objectives. Understanding tradeoffs between these objectives is a critical component of assuring the usefulness of the developed metrics so that they can be used and provide value. Considering tradeoffs between multiple objectives is further compounded by recognizing the uncertainties associated with each metric.

As part of this overall effort, facilitated discussions with stakeholders will allow metrics team leads to not only gather input about existing and proposed metrics and their relevance, but also explore how stakeholders use these metrics and how to they prioritize them to inform decisions. In Year 1, we drew from stakeholder discussions to propose a structured framework within which stakeholders can weigh alternative grid technology or policy solutions using multiple metrics. It is the vision for this project that by Year 3, a structured decision-aiding framework will be developed that enables stakeholders to explore explicitly several tradeoffs across specific decision spaces using a rich set of grid metrics.

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Appendix A

Metrics Inventory

Appendix A

Metrics Inventory

A.1 Reliability

A.1.1 Data

	Categorization			Summary											Historical Supporting Data - Lagging Metrics				
Metric #	Sector	Category *(from list)*	Electric System Infra-structure 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)*	Applic-able to Valu-ation 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	Reliability	Transmission System	Availability of Transmission	NERC collects information to develop transmission metrics that analyze outage frequency, duration, causes, and many other factors related to transmission outages. NERC will also issue an annual public report showing aggregate metrics for each NERC region, and each transmission owner reporting TADS data will be provided a confidential copy of the same metrics for its facilities.	Need to achieve better compliance and create mechanisms to meet FERC order … requirements.	Multiple metrics								Yes, in an aggregated form	National, Region	Year	[REL7]	Need to achieve better compliance and create mechanisms to meet FERC order … requirements.
2	Electricity	Reliability	Distribution System	SARFI	System Average RMS (Variation) Frequency Index	Focus on sag frequency	Avg events per customer									Area/Region	Year	[REL9,] [REL10]	This is considered a Power Quality (PQ) measure - some utilities separate PQ from Reliability; others consider Reliability to be a subset of PQ
3	Electricity	Reliability	Distribution System	SIARFI	System Instantaneous Average RMS (Variation) Frequency Index	Component of SARFI	Events per customer									Area/Region	Year	[REL9,] [REL10]	See SARFI comment
4	Electricity	Reliability	Distribution System	STARFI	System Temporary Average RMS (Variation) Frequency Index	Component of SARFI	Avg events per customer									Area/Region	Year	[REL9,] [REL10]	See SARFI comment
5	Electricity	Reliability	Distribution System	SMARFI	System Momentary Average RMS (Variation) Frequency Index	Component of SARFI	Avg events per customer									Area/Region	Year	[REL9,] [REL10]	See SARFI comment
6	Electricity	Reliability	Distribution System, Transmission System	SAIFI	System Average Interruption Frequency Index	Customers interrupted/customers served	Dimensionless								Yes		Year	[REL11]	May be inconsistently applied from utility to utility making comparisons difficult but not impossible
7	Electricity	Reliability	Distribution System, Transmission System	SAIDI	System Average Interruption Duration Index	Total customer interruption duration/customers served	Minutes per customer								Yes		Year	[REL11]	May be inconsistently applied from utility to utility

	Categorization			Summary											Historical Supporting Data - Lagging Metrics				
Metric #	Sector	Category *(from list)*	Electric System Infra-structure 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)*	Applic-able to Valu-ation 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
																			making comparisons difficult but not impossible
8	Electricity	Reliability	Distribution System, Transmission System	CAIDI	Customer Average Interruption Duration Index	Sum of customer interruption durations / total customers interrupted	Hours per customer										Year	[REL11]	Not all utilities track or report this
9	Electricity	Reliability	Distribution System, Transmission System	CAIFI	Customer Average Interruption Frequency Index	Total customers interrupted/total customers served	Events per unit time per customer										Year	[REL11]	Not all utilities track or report this
10	Electricity	Reliability	Distribution System, Transmission System	CTAIDI	Customer Total Average Interruption Duration Index	A hybrid of CAIDI except customers with multiple interruptions are counted only once	Hours per customer										Year	[REL11]	Not all utilities track or report this
11	Electricity	Reliability	Distribution System	ASAI	Average Service Availability Index	Customer hours service availability / Customer hours service demands	Dimensionless										Year	[REL11]	Not all utilities track or report this
12	Electricity	Reliability	Distribution System	MAIFI	Monthly Average Interruption Frequency Index	Total customer momentary interruptions / total customers served	Monthly events per customer										Year	[REL11]	Not all utilities track or report this
13	Electricity	Reliability	Distribution System	CEMI	Customers Experiencing Multiple Interruptions	Total customers experiencing more than n sustained outages / total customers served	Dimensionless										Year	[REL11]	Not all utilities track or report this
14	Electricity	Reliability	Distribution System	CEMSMI	Customers Experiencing Multiple Sustained Interruption and Momentary Interruptions	Similar to CEMSI but includes momentary and sustained outages	Dimensionless										Year	[REL11]	Not all utilities track or report this
15	Electricity	Reliability	Distribution System	CI	Customers Interrupted		Customers per unit time period										Year	[REL11]	Not all utilities track or report this
16	Electricity	Reliability	Distribution System	CMI	Customer Minutes Interrupted		Minutes per customer per unit time period										Year	[REL11]	Not all utilities track or report this
17	Electricity	Reliability	Distribution System	ASIFI	Average system interruption frequency index	Total connected kVA of load interrupted / total connected kVA served	Dimensionless										Year	[REL11]	Not all utilities track or report this
18	Electricity	Reliability	Distribution System	ASIDI	Average System Interruption Duration Index	Sum of connected kVA duration of load interrupted / total connected kVA served	Hours										Year	[REL11]	Not all utilities track or report this
19	Electricity	Reliability	Distribution System	CELID	Customers Experiencing Long Interruption Durations	total number of customers that have experienced more than eight interruptions in a single reporting year/total customers served	Dimensionless										Year		Not all utilities track or report this
20	Electricity	Reliability	Distribution System	SARI	System Average Restoration Index	∑(Circuit outage durations)/∑(circuit outages); duration greater than 60 seconds; defined over specified time period	Minutes per outage										Year		Not all utilities track or report this

	Categorization			Summary											Historical Supporting Data - Lagging Metrics				
Metric #	Sector	Category *(from list)*	Electric System Infra-structure 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)*	Applic-able to Valu-ation 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
21	Electricity	Reliability	Distribution System	COR	Correct Operation Rate	Number of correct operations/total number of operations commanded	%										Year		Not all utilities track or report this
22	Electricity	Reliability	Distribution System	DELI	Devices Experiencing Long Interruptions	Focus on equipment rather than customers	Count										Year		Not all utilities track or report this; may refer to either utility or customer devices
23	Electricity	Reliability	Distribution System	DEMI	Devices Experiencing Multiple Interruptions	Focus on equipment rather than customers	Count										Year		Not all utilities track or report this; may refer to either utility or customer devices
24	Electricity	Reliability	Transmission System	ACOD	Average Circuit Outage Duration	Transmission outage metric	Minutes								No		Year		Not all utilities track or report this; used to compute TACS
25	Electricity	Reliability	Transmission System	ACSI	Average Circuit Sustained Interruptions	Transmission outage metric	Count/time								No		Year		Not all utilities track or report this; used to compute TACS
26	Electricity	Reliability	Transmission System	TACS	Transmission Availability Composite Score	Complex function of time-weighted outage, outage duration, and time between failure statistics	Dimensionless								No		Year		Computed for transmission utilities by a private company
27	Electricity	Reliability	Transmission System	FOHMY	Forced Outages Per Hundred Circuit Miles Per Year	Used mainly on transmission systems; can be circuit or system average	Outages per hundred miles per year								No		Year		Note that some utilities do not agree that this is a useful metric

A.1.2 References

Citation/ Data Source Ref #	Citation/Data Source
REL1	Presidential Policy Directive, 2013
REL2	Summary of Proposed Metrics – QER Technical Workshop on Energy Sector Resilience Metrics (4/29/2014)
REL3	http://www.oe.netl.doe.gov/OE417_annual_summary.aspx
REL4	http://www.sciencedirect.com/science/article/pii/S0301421514002237#bib26
REL5	CPS1 scores
REL6	GADS, http://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx
REL7	TADS, http://www.nerc.com/pa/RAPA/tads/Pages/default.aspx
REL8	http://www.nerc.com/pa/RAPA/ri/Pages/InterconnectionFrequencyResponse.aspx
REL9	IEEE Trans Power Delivery, Vol 13, Jan 1998, pp.254-259
REL10	EPRI Reliability Benchmarking Application Guide For Utility/Customer PQ Indices
REL11	1366-2012 IEEE Guide for Electric Power Distribution Reliability Indices

REL12	Impact of Low Rotational Inertia on Power System Stability and Operation (Andreas Ulbig, et. al.)
REL13	http://www.nerc.com/pa/RAPA/IROLSOLExceedance/ALR3-5_Form.pdf

A.2 Resilience

A.2.1 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	Resilience	Transmission system, Distribution system	Electrical service, measured with one or more of the following units: Cumulative customer-hours of outages; Cumulative customer energy demand not served; Average number (or percentage) of customers that experience an outage during a specified time period				Quantitative, Numerical	Outcome	Decision Making, Learning	Utility, System Operators	Communities, federal/state/local agency/regulator	Leading (primarily), but also lagging; depends on particular analysis and usage	Yes	Yes, in some cases (e.g., OMS have much outage data)	Interconnection, RTO, State, Utility service area, Distribution system footprint, Customer footprint	TBD: triggers for calculations could be change in hazard conditions, new investment planning initiative; perhaps an annual review		Note: for leading metric analyses, consequence data may include uncertainty, i.e., be characterized as a probability distribution, histogram, mean & standard deviation, etc. In addition to selecting the consequence categories, it is important to select the appropriate statistical property (e.g., mean, value at risk, maximum, minimum, etc.) that best fits the analysis and risk tolerance of the interested parties.
2	Electricity	Resilience	Transmission system, Distribution system	Critical Electrical Service, measured with one or more of the following units: Cumulative critical customer-hours of outages; Critical customer energy demand not served; Average number (or percentage) of critical loads that experience an outage				Quantitative, Numerical	Outcome	Decision Making, Learning	Utility, System Operators	Communities, federal/state/local agency/regulator	Leading (primarily), but also lagging; depends on particular analysis and usage	Yes	Yes, in some cases (e.g., OMS have much outage data)	Interconnection, RTO, State, Utility service area, Distribution system footprint, Customer footprint	TBD: triggers for calculations could be change in hazard conditions, new investment planning initiative; perhaps an annual review		
		Resilience	Transmission system, Distribution system	Restoration, measured with one or more of the following units: time to recovery, cost of recovery				Quantitative, Numerical	Outcome	Decision Making, Learning	Utility, System Operators	Communities, federal/state/local agency/regulator	Leading (primarily), but also lagging; depends on particular analysis and usage	Yes	Yes, in some cases	Interconnection, RTO, State, Utility service area, Distribution system footprint, Customer footprint	TBD: triggers for calculations could be change in hazard conditions, new investment planning initiative; perhaps an annual review		
		Resilience	Transmission system, Distribution system	Monetary, measured with one or more of the following units: Loss of utility revenue; Cost of grid damages; Cost of recovery; Avoided outage cost				Quantitative, Numerical	Outcome	Decision Making, Learning	Utility, System Operators	Communities, federal/state/local agency/regulator	Leading (primarily), but also lagging; depends on particular analysis and usage	Yes	Yes, in some cases	Interconnection, RTO, State, Utility service area, Distribution system footprint, Customer footprint	TBD: triggers for calculations could be change in hazard conditions, new investment planning initiative; perhaps an annual review		

	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**
		Resilience	Transmission system, Distribution system	Community function, measured with one or more of the following units: Critical services without power (e.g., hospitals, fire stations, police stations); Critical services without power for more than N hours (e.g., N > hours of back up fuel requirement); Key production facilities without power Key military facilities without power ;				Quantitative, Numerical	Outcome	Decision Making, Learning	Utility, System Operators	Communities, federal/state/local agency/regulator	Leading (primarily), but also lagging; depends on particular analysis and usage	Yes	yes, in some cases	Interconnection, RTO, State, Utility service area, Distribution system footprint, Customer footprint	TBD: triggers for calculations could be change in hazard conditions, new investment planning initiative; perhaps an annual review		
		Resilience	Transmission system, Distribution system	Monetary measurements for the community, measured with one or more of the following units: Loss of assets and perishables; Business interruption costs; Impact on Gross Municipal Product (GMP) or Gross Regional Product (GRP);				Quantitative, Numerical	Outcome	Decision Making, Learning	Utility, System Operators	Communities, federal/state/local agency/regulator	Leading (primarily), but also lagging; depends on particular analysis and usage	Yes	Yes, in some cases	Interconnection, RTO, State, Utility service area, Distribution system footprint, Customer footprint	TBD: triggers for calculations could be change in hazard conditions, new investment planning initiative; perhaps an annual review		

A.2.2 References

Citation/ Data Source Ref #	Citation/Data Source

A.3 Flexibility

A.3.1 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 IRP. 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 IRP. A higher value indicates more variable renewables are included in the portfolio.
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.

	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
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.
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.

	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**
6	Electricity	Flexibility	Generation central	Insufficient Ramping Resource Expectation	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, it similar to the EPRI approach albeit more probabilistic.
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.

	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
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 the of simple- and combined-cycle gas-fired units) to the flexibility demand (based on the volatility observed in load, generation and transmission curtailments, and the uncertainty inherent in predicting loads, wind generation and unexpected events).	Process to evaluate the flexibility of a utilities 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 use 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, highlighting the economic implications of flexibility.
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 VERs) using one-minute data.	Measures the maximum net demand variability faced by a balancing authority. Ultimately, the 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 of: How much capacity and operating flexibility is needed for a power system to meet the 1 day in 10 years Loss of Load Expectation (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 called SERVM by ASTRAPE consulting.
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.	In order 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 U.S.
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.
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.

	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
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.
16	Electricity	Flexibility	Generation central (RTO, ISOs)	Control Performance Standards (CPS1, CPS2, BAAL)	Control performance standards measure a balancing area's Area Control Error (ACE), 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.

A.3.2 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.
FLEX4	Lannoye, E., D. Flynn, and M. O'Malley. 2012. "Evaluation of Power System Flexibility." IEEE Transactions on Power Systems 27 (2): 922–31. doi:10.1109/TPWRS.2011.2177280.
FLEX5	Zhao, J., T. Zheng, and E. Litvinov. 2015. "A Unified Framework for Defining and Measuring Flexibility in Power System." IEEE Transactions on Power Systems PP (99): 1–9. doi:10.1109/TPWRS.2015.2390038.
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.
FLEX8	Flexibility Metrics and Standards Project – a California Energy Systems for the 21st Century (CES-21) Project: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=9282
FLEX9	Mills, Andrew, and Joachim Seel. 2015. "Flexibility Inventory for Western Resource Planners." LBNL-1003750. Berkeley, CA: Lawrence Berkeley National Laboratory. https://emp.lbl.gov/sites/all/files/lbnl-1003750_0.pdf.
FLEX10	CAISO. Final Flexible Capacity Needs Assessment for 2017. https://www.caiso.com/Documents/FinalFlexibleCapacityNeedsAssessmentFor2017.pdf
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.

A.4 Sustainability

A.4.1 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

	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	Sustainability	Generation central	Electric sector CO_2 emissions from GHGRP	Absolute CO_2 emissions as reported to the GHGRP under mandatory facility reporting to EPA	Mandatory reporting under EPA's Greenhouse Gas Reporting Program (CFR 40 Part 98); facilities that emit 25,000 metric tons or more per year of GHGs are required to submit annual reports to EPA under the GHGRP	Metric tons of CO_2 equivalents	Absolute	Outcome	Learning, Decision-making, Accountability, Demonstration	EPA	Utility	Lagging	Yes	Yes	Generation plant	Annually	SUS1	
2	Electricity	Sustainability	Generation central	Electric sector GHG emissions from GHGI	Absolute GHG emissions as estimated by the EPA's Greenhouse Gas Inventory (GHGI), an annual top-down assessment of total US GHG emissions and removals by source and economic sector	For submission to the United Nations in accordance with the Framework Convention on Climate Change	Metric tons of CO_2 equivalents	Absolute	Outcome	Learning, Decision-making, Accountability, Demonstration	United Nations	Policy makers	Lagging	No	Yes	National	Annually	SUS2	
3	Electricity	Sustainability	Generation central	Electric sector GHG emissions from eGRID	Absolute GHG emissions as compiled by the EPA into its eGRID data product; data sources include Clean Air Markets program (CAMD) and the EIA's Monthly Energy Review (MER)	For consumers, researchers, and other stakeholders to develop GHG inventories, carbon footprints, consumer information disclosure, avoided emission estimates, etc.	Pounds of CO_2; Pounds of N2O; Pounds of CH_4; Pounds of CO_2 equivalents	Absolute	Outcome	Learning, Decision-making, Accountability, Demonstration	Consumers	Utility	Lagging	Yes	Yes	Boiler	Biennially	SUS3	

	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**
4	Electricity	Sustainability	Generation central	Electric sector GHG intensity from eGRID	GHG intensity as estimated in the EPA's eGRID data product; data sources include Clean Air Markets program (CAMD) and the EIA's Monthly Energy Review (MER)	For consumers, researchers, and other stakeholders to develop GHG inventories, carbon footprints, consumer information disclosure, avoided emission estimates, etc.	Pounds of CO_2 per MWh; Pounds of N_20 per MWh; Pounds of CH_4 per MWh; Pounds of CO_2 equivalents per MWh	Intensity	Outcome	Learning, Decision-making, Accountability, Demonstration	Consumers	Utility	Lagging	Yes	Yes	Generation plant	Biennially	SUS3	
5	Electricity	Sustainability	Generation central	Electric sector CO_2 emissions from CAMD	Absolute CO_2 emissions as reported to the EPA Clean Air Markets Division (CAMD) for mandatory reporting of CO_2 emissions data from continuous emission monitoring systems	Mandatory reporting under EPA's Acid Rain Program (CFR 40 Part 75)	Metric tons of CO_2	Absolute	Outcome	Learning, Decision-making, Accountability, Demonstration	EPA	Utility	Lagging	Yes	Yes	Boiler	Hourly	SUS4	
6	Electricity	Sustainability	Generation central	Electric sector CO_2 emissions from MER	Absolute CO_2 emissions as compiled by the EIA in its Monthly Energy Review (MER)	To provide independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding	Metric tons of CO_2	Absolute	Outcome	Learning, Decision-making, Accountability, Demonstration	Consumers	Policy makers	Lagging	Yes	Yes	State	Monthly	SUS5	
7	Electricity	Sustainability	Generation central	Electric sector CO_2 emissions from EIA's EPA	Absolute CO_2 emissions as compiled by the EIA in its Electric Power Annual (EPA)	To provide independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding	Metric tons of CO_2	Absolute	Outcome	Learning, Decision-making, Accountability, Demonstration	Consumers	Policy makers	Lagging	Yes	Yes	Facility	Annually	SUS6	

	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**
8	Electricity	Sustainability	Generation central	Electric sector CO_2 emissions from EIA's STEO	Absolute CO_2 emissions as projected by the EIA in its Short-Term Energy Outlook	To provide independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding	Metric tons of CO_2	Absolute	Outcome	Learning, Decision-making, Accountability, Demonstration	Consumers	Policy makers	Leading	No	Yes	National	Monthly	SUS7	
9	Electricity	Sustainability	Generation central	Electric sector CO_2 emissions from EIA's AEO	Absolute CO_2 emissions as compiled by the EIA in its Annual Energy Outlook	To provide independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding	Metric tons of CO_2	Absolute	Outcome	Learning, Decision-making, Accountability, Demonstration	Consumers	Policy makers	Leading	Yes	Yes	National	Annually	SUS8	
11	Electricity	Sustainability	Generation, transmission, and distribution	Corporate CO_2 emissions from SASB	Absolute GHG emissions (gross global scope 1) as reported to the Sustainability Accounting Standards Board	To develop and disseminate sustainability accounting standards that help public corporations disclose material, decision-useful information to investors	Metric tons of CO_2 equivalents	Absolute	Outcome	Learning, Decision-making, Accountability, Demonstration	Utility	Consumer	Lagging	No	Varies	Corporation	Varies	SUS9	
12	Electricity	Sustainability	Generation, transmission, and distribution	GHG emissions covered under emissions-limiting regulations	Percentage of emissions covered under emissions-limiting regulations	To develop and disseminate sustainability accounting standards that help public corporations disclose material, decision-useful information to investors	Percentage	Quantitative	Process	Learning, Decision-making, Accountability, Demonstration	Utility	Consumer	Lagging	No	Varies	Corporation	Varies	SUS9	

	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**
12	Electricity	Sustainability	Generation, transmission, and distribution	GHG emissions covered under emissions-reporting regulations	Percentage of emissions covered under emissions-reporting regulations	To develop and disseminate sustainability accounting standards that help public corporations disclose material, decision-useful information to investors	Percentage	Quantitative	Process	Learning, Decision-making, Accountability, Demonstration	Utility	Consumer	Lagging	No	Varies	Corporation	Varies	SUS9	
12	Electricity	Sustainability	Generation, transmission, and distribution	Corporate emission reduction strategy	Description of long-term and short-term strategy or plan to manage Scope 1 emissions, emission-reduction targets, and an analysis of performance against those targets	To develop and disseminate sustainability accounting standards that help public corporations disclose material, decision-useful information to investors	NA	Qualitative	Process	Learning, Decision-making, Accountability, Demonstration	Utility	Consumer	Leading	No	Varies	Corporation	Varies	SUS9	
12	Electricity	Sustainability	Generation, transmission, and distribution	Corporate fulfillment of RPS target by market	Percentage fulfillment of RPS target by market	To develop and disseminate sustainability accounting standards that help public corporations disclose material, decision-useful information to investors	Percentage	Quantitative	Process	Learning, Decision-making, Accountability, Demonstration	Utility	Consumer	Lagging	No	Varies	Corporation	Varies	SUS9	
12	Electricity	Sustainability	Generation, transmission, and distribution	Customers served in RPS markets	Number of customers served in markets subject to renewable portfolio standards	To develop and disseminate sustainability accounting standards that help public corporations disclose material, decision-useful information to investors	Number of customers	Absolute	Process	Learning, Decision-making, Accountability, Demonstration	Utility	Consumer	Lagging	No	Varies	Corporation	Varies	SUS9	

	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	Sustainability	Generation central	Electric sector CO_2 intensity from EIA	GHG intensity used to compute CO_2 emissions from fuel consumption in the EIA's Monthly Energy Review (MER) and the EIA's Electric Power Annual (EPA)	To provide independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding	Million metric tons of CO_2 per quadrillion Btu	Intensity	Outcome	Learning, Decision-making, Accountability, Demonstration	EIA		Lagging	No	Yes	National	Not recently updated	SUS10	
14	Electricity	Sustainability	Generation central	Electric sector CO_2 intensity from the EPA's GHGRP	GHG intensity reported in the Code of Federal Regulations for use in the Greenhouse Gas Reporting Program (GHGRP)	Mandatory reporting under EPA's Greenhouse Gas Reporting Program (CFR 40 Part 98); facilities that emit 25,000 metric tons or more per year of GHGs are required to submit annual reports to EPA under the GHGRP	Kilograms CO_2 per million Btu	Intensity	Outcome	Learning, Decision-making, Accountability, Demonstration	EPA		Lagging	No	Yes	National	One-time release	SUS11	
15	Electricity	Sustainability	Generation central	Electric sector SO_2 and NOx emissions from eGRID	Absolute NOx and SO_2 emissions as compiled by the EPA into its eGRID data product; data sources include Clean Air Markets program (CAMD) and the EIA's Monthly Energy Review (MER)	For consumers, researchers and other stakeholders to develop criteria pollutant emission inventories, air quality analysis, consumer information disclosure, avoided emission estimates, etc.	Tons of NOx and SO_2	Absolute	Outcome	Learning, Decision-making, Accountability, Demonstration	Consumers	Utility	Lagging	Yes	Yes	Boiler	Biennially	SUS3	

	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**
15	Electricity	Sustainability	Generation central	Electric sector SO_2 and NOx emissions from eGRID	Absolute NOx and SO_2 emissions as compiled by the EPA into its eGRID data product; data sources include Clean Air Markets program (CAMD) and the EIA's Monthly Energy Review (MER)	For consumers, researchers and other stakeholders to develop criteria pollutant emission inventories, air quality analysis, consumer information disclosure, avoided emission estimates, etc.	lb NOx and SO_2 per MWh.	intensity	Outcome	Learning, Decision-making, Accountability, Demonstration	Consumers	Utility	Lagging	Yes	Yes	Generation plant	Biennially	SUS3	
16	Electricity	Sustainability	Generation central	Electric sector SO_2 and NOx emissions from CAMD	Absolute SO2 and NOx emissions as reported to the EPA Clean Air Markets Division (CAMD) for mandatory reporting from continuous emission monitoring systems	Mandatory reporting under EPA's Acid Rain Program (CFR 40 Part 75)	lb of SO_2 and NOx	Absolute	Outcome	Learning, Decision-making, Accountability, Demonstration	EPA	Utility	Lagging	Yes	Yes	Boiler	Hourly	SUS4	
16	Electricity	Sustainability	Generation central	Electric sector SO_2 and NOx emissions from CAMD	Absolute SO2 and NOx emissions as reported to the EPA Clean Air Markets Division (CAMD) for mandatory reporting from continuous emission monitoring systems	Mandatory reporting under EPA's Acid Rain Program (CFR 40 Part 75)	lb of SO_2 and NOx per mmBTU (and NOx per MWh)	Absolute	Outcome	Learning, Decision-making, Accountability, Demonstration	EPA	Utility	Lagging	Yes	Yes	Boiler	Hourly	SUS4	

	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**
17	Electricity	Sustainability	Generation central	Electric sector SO_2 and NOx emissions from EIA's EPA	Absolute NOx and SO_2 emissions as compiled by the EIA in its Electric Power Annual (EPA)	To provide independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding	lbs SO_2 and NOx	Absolute	Outcome	Learning, Decision-making, Accountability, Demonstration	Consumers	Policy makers	Lagging	Yes	Yes	State	Annually	SUS6	
18	Electricity	Sustainability	Generation central	Electric sector SO_2, NOx, mercury emissions from EIA's AEO	Absolute SO_2, NOx, and mercury emissions as compiled by the EIA in its Annual Energy Outlook	To provide independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding	Short Tons SO_2, NOx, Mercury	Absolute	Outcome	Learning, Decision-making, Accountability, Demonstration	Consumers	Policy makers	Leading	Yes	Yes	National	Annually	SUS8	
19	Electricity	Sustainability	Generation central	All sector SO_2, NOx, PM2.5 and heavy metals from EPA's National Emissions Inventory	All sector SO_2, NOx, PM2.5 and heavy metals from EPA's National Emissions Inventory	To provide independent and impartial emissions information to promote sound policymaking, efficient markets, and public understanding	short tons or lb of criteria pollutants and heavy metals	Absolute	Outcome	Learning, Decision-making, Accountability, Demonstration	Consumers	Policy makers	Lagging	Yes	Yes	Plant	Varies	SUS12	
19	Electricity	Sustainability	Distributed generation	All sector SO_2, NOx, PM2.5 and heavy metals from EPA's National Emissions Inventory	All sector SO_2, NOx, PM2.5 and heavy metals from EPA's National Emissions Inventory	To provide independent and impartial emissions information to promote sound policymaking, efficient markets, and public understanding	short tons or lb of criteria pollutants and heavy metals	Absolute	Outcome	Learning, Decision-making, Accountability, Demonstration	Consumers	Policy makers	Lagging	Yes	Yes	County	Varies	SUS12	

A.4.2 References

Citation/ Data Source Ref #	Citation/Data Source
SUS1	https://www.epa.gov/ghgreporting/ghg-reporting-program-data-sets
SUS2	https://www.epa.gov/ghgemissions/us-greenhouse-gas-inventory-report-1990-2014

SUS3	https://www.epa.gov/energy/egrid
SUS4	https://ampd.epa.gov/ampd/
SUS5	http://www.eia.gov/totalenergy/data/monthly/#environment
SUS6	http://www.eia.gov/electricity/annual/
SUS7	http://www.eia.gov/forecasts/steo/
SUS8	http://www.eia.gov/forecasts/aeo/
SUS9	SASB. 2016. Sustainability Accounting Standard - Infrastructure Sector. Electric Utilities Sustainability Accounting Standard. SICS IF0101. Available at: http://www.sasb.org/
SUS10	http://www.eia.gov/electricity/annual/html/epa_a_03.html
SUS11	EPA. 2013. 40 CFR Part 98, Subpart C, Table C-1 to Subpart C of Part 98 - Default CO2 Emission Factors and High Heat Values for Various Types of Fuel. Latest revision available at https://www.gpo.gov/fdsys/pkg/FR-2013-11-29/pdf/2013-27996.pdf#page=48
SUS12	https://www.epa.gov/air-emissions-inventories/national-emissions-inventory-nei

A.5 Affordability

A.5.1 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	Affordability	All	Levelized cost of electricity (LCOE)	total cost of installing and operating a project expressed in dollars per kilowatt-hour of electricity generated by the system over its life	LCOE has been used for calculating the cost-effectiveness of projects. By incorporating different categories of cash flows, different stakeholder interests can be examined.	$/MWh, $/kWh	Absolute	Outcome	Decision making	Ultility	Regulator	Leading	Yes				AFF1	
2	Electricity	Affordability	All	Internal Rate of Return (IRR)	the discount rate that makes the NPV of the cost and revenue stream equal to zero	IRR has been used for calculating the cost-effectiveness of projects. By incorporating different categories of cash flows, different stakeholder interests can be examined. Rational investors would undertake projects as ranked by descending IRR order.	Percentage	Absolute	Outcome	Decision making	Ultility	Regulator	Leading	Yes				AFF1	
3	Electricity	Affordability	All	Simple Payback Period (SPP)	the length of time after the first investment that the undiscounted sum of costs and revenues equals zero	Easy to understand representation of cost effectiveness	# of years or months	Absolute	Outcome	Decision making	Ultility	Regulator	Leading	Yes				AFF2	While simple to calculate, it does not give as meaningful a result as the NPV or IRR, because it only tells how long it takes until the costs have been recovered, without providing an estimation of the total return. It does not capture any information about the time value of money, nor the impact over the full life of the project.
4	Electricity	Affordability	All	Net Revenue Requirements	the annual stream of revenue necessary to recover the total costs of a project including capital (in the form of depreciation), operating costs including fuel, financing costs including interest and required return on rate on equity, and taxes including both costs and incentives.	Revenue requirements are typically calculated and used on a company-wide basis, but the impacts of single projects on revenue requirements can be calculated by applying the rules on just the subset of costs applicable to the project.	$/year	Absolute	Outcome	Decision making	Ultility	Regulator	Leading	Yes				AFF3	
5	Electricity	Affordability	All	Avoided Cost	net change in the costs of the overall system with the development of the specified project	used by utilities and regulators for establishing the value of a project compared to its alternatives and for setting the value of distributed generation technologies	$	Absolute	Outcome	Decision making	Ultility	Regulator	Leading	Yes				AFF1	It can be a complicated calculation, subject to defining the boundaries of the analysis and adequately simulating the system. It captures items such as the energy avoided from other generators because of the new project (either a generator, demand response, or energy efficiency measures), capacity, substation, or transmission and distribution expansion

	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**
6	Electricity	Affordability	All	Customer cost burden	Proportion of customer income devoted to purchasing desired level of electricty service	Foundational to estimating customer affordability	fraction	Numerical or intensity	Outcome	Learning/ Demonstration	Regulator	Consumer advocate; other advocacy groups	Lagging	Yes	Yes	National, Interconnection, RTO, State, Utility service area, Distribution system footprint	Annual/ monthly	AFF4	Straightforward estimation for residential sector; more complicated for commercial and industrial sectors; public data sources for customer cost may have limitations compared to actual billing data.
7	Electricity	Affordability	All	Affordability gap factor	Indication of the difference between affordable customer costs and observed customer costs	Provides scale to the affordability question - How unaffordable are electricity costs on average?	factor or fraction	Numerical or intensity	Outcome	Learning/ Demonstration	Regulator	Consumer advocate; other advocacy groups	Lagging	Yes	Yes	National, Interconnection, RTO, State, Utility service area, Distribution system footprint	Annual/ monthly	AFF4, AFF5, AFF6	Straightforward estimation for residential sector; more complicated for commercial and industrial sectors; public data sources for customer cost may have limitations compared to actual billing data.
8	Electricity	Affordability	All	Affordability gap headcount	Number of households facing costs higher than an established affordable threshold	Provides scale to the affordability question - How many customers face unaffordable electricity?	# Households or % of households	Absolute	Outcome	Learning/ Demonstration	Regulator	Consumer advocate; other advocacy groups	Lagging	Yes	Yes	National, Interconnection, RTO, State, Utility service area, Distribution system footprint	Annual/ monthly	AFF4, AFF7	Straightforward estimation for residential sector; more complicated for commercial and industrial sectors; public data sources for customer cost may have limitations compared to actual billing data.
9	Electricity	Affordability	All	Affordability gap index	temporal index of affordability gap factor compared to a base year	Answers the question: Is electricity becoming more or less affordable?	index	Numerical	Outcome	Learning/ Demonstration	Regulator	Consumer advocate; other advocacy groups	Lagging	Yes	Yes	National, Interconnection, RTO, State, Utility service area, Distribution system footprint	Annual/ monthly	AFF4, AFF7	Straightforward estimation for residential sector; more complicated for commercial and industrial sectors; public data sources for customer cost may have limitations compared to actual billing data.
10	Electricity	Affordability	All	Affordability gap headcount index	temporal index of affordability gap headcount compared to a base year	Answers the question: Are more or less customers facing unaffordable electricity costs?	index	Numerical	Outcome	Learning/ Demonstration	Regulator	Consumer advocate; other advocacy groups	Lagging	Yes	Yes	National, Interconnection, RTO, State, Utility service area, Distribution system footprint	Annual/ monthly	AFF4, AFF7	Straightforward estimation for residential sector; more complicated for commercial and industrial sectors; public data sources for customer cost may have limitations compared to actual billing data.

A.5.2 References

Citation/ Data Source Ref #	Citation/Data Source
AFF1	Short W., Packey DJ, & Holt T. 1995. A Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies. NREL/TP-462-5173, National Renewable Energy Laboratory, Golden, Colorado. Available at: http://www.nrel.gov/docs/legosti/old/5173.pdf
AFF2	Hart R & Liu B. 2015. Methodology for Evaluating Cost-effectiveness of Commercial Energy Code Changes. PNNL-23923, Rev 1, Pacific Northwest National Laboratory, Richland, Washington. Available online at: https://www.energycodes.gov/sites/default/files/documents/commercial_methodology.pdf
AFF3	Hadley SW, Hill LJ, and Perlack RD. 1993. Report on the Study of Tax and Rate Treatment of Renewable Energy Projects. ORNL-6772, Oak Ridge National Laboratory, Oak Ridge, Tennessee. Available at: http://www.ornl.gov/~webworks/cpr/v823/rpt/68456.pdf
AFF4	Colton (2011) http://www.nyserda.ny.gov/-/media/Files/EDPPP/LIFE/Resources/2008-2010-affordability-gap.pdf
AFF5	Drehobl and Ross (2016) Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low Income and Underserved Communities. American Council for an Energy Efficient Economy, City, State.
AFF6	Heindl and Schuessler (2015) Dynamic properties of energy affordability measures. Energy Policy 86:123–132.
AFF7	Fisher, Sheehan, and Colton. 2013. "Home Energy Affordability Gap." Accessed online at: http://www.homeenergyaffordabilitygap.com/.

A.6 Security

A.6.1 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 Classific-ation *(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	Security	All	Physical Security	Accounts for presence of physical security measures such as fences, gates, etc.	Documents utility's current CIKR protection posture and overall security awareness	0 to 100%	Numerical	Process	Account-ability	Utility	State Regulator	Lagging	YES	YES (public & DHS)	Distribution system footprint	Annual	Argonne National Laboratory, 2009. Constructing Vulnerability and Protective Measures Indices for the Enhanced Critical Infrastructure Protection Program, available at http://www.ipd.anl.gov/anlpubs/2009/10/65406.pdf	Go Cubs Go!
2	Electricity	Security	All	Security Force	Staffing, equipment, weaponry, training, patrols, after hour security, etc.	Documents utility's current CIKR protection posture and overall security awareness	0 to 100%	Numerical	Process	Account-ability	Utility	State Regulator	Lagging	YES	YES (public & DHS)	Distribution system footprint	Annual	Argonne National Laboratory, 2009. Constructing Vulnerability and Protective Measures Indices for the Enhanced Critical Infrastructure Protection Program, available at http://www.ipd.anl.gov/anlpubs/2009/10/65406.pdf	
3	Electricity	Security	All	Security Management	Business continuity plan, security plan, threat levels, background checks, etc.	Documents utility's current CIKR protection posture and overall security awareness	0 to 100%	Numerical	Process	Account-ability	Utility	State Regulator	Leading	YES	YES (public & DHS)	Distribution system footprint	Annual	Argonne National Laboratory, 2009. Constructing Vulnerability and Protective Measures Indices for the Enhanced Critical Infrastructure Protection Program, available at http://www.ipd.anl.gov/anlpubs/2009/10/65406.pdf	
4	Electricity	Security	All	Information Sharing	Threat sources and information sharing mechanisms	Documents utility's current CIKR protection posture and overall security awareness	0 to 100%	Numerical	Process	Account-ability	Utility	State Regulator	Leading	YES	YES (public & DHS)	Distribution system footprint	Annual	Argonne National Laboratory, 2009. Constructing Vulnerability and Protective Measures Indices for the Enhanced Critical Infrastructure Protection Program, available at http://www.ipd.anl.gov/anlpubs/2009/10/65406.pdf	
5	Electricity	Security	All	Security Activity History/ Background	New protective measures, random security measures, etc.	Documents utility's current CIKR protection posture and overall security awareness	0 to 100%	Numerical	Process	Account-ability	Utility	State Regulator	Lagging	YES	YES (public & DHS)	Distribution system footprint	Annual	Argonne National Laboratory, 2009. Constructing Vulnerability and Protective Measures Indices for the Enhanced Critical Infrastructure Protection Program, available at http://www.ipd.anl.gov/anlpubs/2009/10/65406.pdf	

	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 Classific-ation *(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
6	Electricity	Security	All	BES Security Metric 1: Reportable Cyber Security Incidents	The number of reportable cyber security incidents that result in a loss of load, summed on a quarterly basis; this is a lagging metric	Describes how prepared the electric sector is to a physical attack.	≥0 (dimensionless)	Numerical	Process	Account-ability	NERC		Lagging	NO	YES (from NERC)	National	Quarterly	NERC, 2015. Bulk Electric System Security Metrics Working Draft, available at http://www.nerc.com/comm/CIPC/Bulk%20Electric%20System%20Security%20Metrics%20Working%20G1/BES_Security_Metrics_CIPC_March_2015.pdf	This metric is applied at the national level and there is insufficient public data for its application at the utility- or State-level.
7	Electricity	Security	All	BES Security Metric 2: Reportable Physical Security Events	The number of physical security reportable events that occur over time as a result of threats to a facility or BES control center or damage or destruction to a facility, summed on a quarterly basis; this is a lagging metric	Describes how prepared the electric sector is to a physical attack.	≥0 (dimensionless)	Numerical	Process	Account-ability	NERC		Lagging	NO	YES (from NERC)	National	Quarterly	NERC, 2015. Bulk Electric System Security Metrics Working Draft, available at http://www.nerc.com/comm/CIPC/Bulk%20Electric%20System%20Security%20Metrics%20Working%20G1/BES_Security_Metrics_CIPC_March_2015.pdf	This metric is applied at the national level and there is insufficient public data for its application at the utility- or State-level.
8	Electricity	Security	All	BES Security Metric 3: ES-ISAC Membership	The number of ES-ISAC member organizations, summed on a quarterly basis; this is a leading metric.	Describes how prepared the electric sector is to a physical attack.	≥0 (dimensionless)	Numerical	Process	Decision making	NERC		Leading	NO	YES (from NERC)	National	Quarterly	NERC, 2015. Bulk Electric System Security Metrics Working Draft, available at http://www.nerc.com/comm/CIPC/Bulk%20Electric%20System%20Security%20Metrics%20Working%20G1/BES_Security_Metrics_CIPC_March_2015.pdf	This metric could be applied at the utility-level.
9	Electricity	Security	All	BES Security Metric 4: Industry-Sourced Information Sharing	The number of ES-ISAC Incident Bulletins [currently known as Watchlist entries], summed on a quarterly basis; this is a leading metric.	Describes how prepared the electric sector is to a physical attack.	≥0 (dimensionless)	Numerical	Process	Decision making	NERC		Leading	NO	YES (from NERC)	National	Quarterly	NERC, 2015. Bulk Electric System Security Metrics Working Draft, available at http://www.nerc.com/comm/CIPC/Bulk%20Electric%20System%20Security%20Metrics%20Working%20G1/BES_Security_Metrics_CIPC_March_2015.pdf	This metric is applied at the national level and there is insufficient public data for its application at the utility- or State-level.
10	Electricity	Security	All	BES Security Metric 5: Global Cyber Vulnerabilities	The number of global cyber vulnerabilities with a CVSS [Common Vulnerability Scoring System, NIST 2015] of 7 or higher; this is a lagging metric.	Describes how prepared the electric sector is to a physical attack.	≥0 (dimensionless)	Numerical	Process	Account-ability	NERC		Lagging	NO	YES (from NERC)	National	Quarterly	NERC, 2015. Bulk Electric System Security Metrics Working Draft, available at http://www.nerc.com/comm/CIPC/Bulk%20Electric%20System%20Security%20Metrics%20Working%20G1/BES_Security_Metrics_CIPC_March_2015.pdf	This metric is applied at the national level and there is insufficient public data for its application at the utility- or State-level.
11	Electricity	Security	Distribution	Number of instances of copper theft	Tracks the impact of copper theft and vandalism	Describes how prepared the electric sector is to a physical attack.	≥0 (dimensionless)	Numerical	Process	Account-ability	Utility	State Regulator	Lagging	NO	Proprietary utility data	Utility	Monthly	CPUC, 2015. Regulation of Physical Security for the Electric Distribution System, available at http://www.cpuc.ca.gov/NR/rdonlyres/930FCC00-BE2F-4BCF-9B68-2CA2CDC38186/0/PhysicalSecurityfortheUtilityIndustry20150210.pdf	This metrics depends on proprietary utility data that is difficult to collect
12	Electricity	Security	Distribution	Number of successful or unsuccessful intrusion or attack	This metric captures the total number of attacks against a given utility's facilities	Describes how prepared the electric sector is to a physical attack.	≥0 (dimensionless)	Numerical	Process	Account-ability	Utility	State Regulator	Lagging	NO	Proprietary utility data	Utility	Monthly	CPUC, 2015. Regulation of Physical Security for the Electric Distribution System, available at http://www.cpuc.ca.gov/NR/rdonlyres/930FCC00-BE2F-4BCF-9B68-2CA2CDC38186/0/PhysicalSecurityfortheUtilityIndustry20150210.pdf	This metrics depends on proprietary utility data that is difficult to collect

	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 Classific-ation *(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	Security	Distribution	Number of false or nuisance alarms	Collection of the number of non-attack-related incidents for a given utility	Describes how prepared the electric sector is to a physical attack.	≥0 (dimensionless)	Numerical	Process	Accountability	Utility	State Regulator	Lagging	NO	Proprietary utility data	Utility	Monthly	CPUC, 2015. Regulation of Physical Security for the Electric Distribution System, available at http://www.cpuc.ca.gov/NR/rdonlyres/930FCC00-BE2F-4BCF-9B68-2CA2CDC38186/0/PhysicalSecurityfortheUtilityIndustry20150210.pdf	This metrics depends on proprietary utility data that is difficult to collect
14	Electricity	Security	Distribution	Condition of all monitoring equipment	The number of times that the security system is unable to respond and detect a physical security incident.	Describes how prepared the electric sector is to a physical attack.	Qualitative	Qualitative	Process	Decision making	Utility	State Regulator	Lagging	NO	Proprietary utility data	Utility	Monthly	CPUC, 2015. Regulation of Physical Security for the Electric Distribution System, available at http://www.cpuc.ca.gov/NR/rdonlyres/930FCC00-BE2F-4BCF-9B68-2CA2CDC38186/0/PhysicalSecurityfortheUtilityIndustry20150210.pdf	This metrics depends on proprietary utility data that is difficult to collect
15	Electricity	Security	Distribution	Performance of security personnel in training exercises and on tests	Describes how prepared the electric sector is for a physical attack.	Describes how prepared the electric sector is to a physical attack.	Qualitative	Qualitative	Process	Decision making	Utility	State Regulator	Lagging	NO	Proprietary utility data	Utility	Monthly	CPUC, 2015. Regulation of Physical Security for the Electric Distribution System, available at http://www.cpuc.ca.gov/NR/rdonlyres/930FCC00-BE2F-4BCF-9B68-2CA2CDC38186/0/PhysicalSecurityfortheUtilityIndustry20150210.pdf	This metrics depends on proprietary utility data that is difficult to collect
16	Electricity	Security	Distribution	Number of problems found with condition of deterrence and monitoring measures	Describes how prepared the electric sector is for a physical attack.	Describes how prepared the electric sector is to a physical attack.	≥0 (dimensionless)	Numerical	Process	Accountability	Utility	State Regulator	Lagging	NO	Proprietary utility data	Utility	Monthly	CPUC, 2015. Regulation of Physical Security for the Electric Distribution System, available at http://www.cpuc.ca.gov/NR/rdonlyres/930FCC00-BE2F-4BCF-9B68-2CA2CDC38186/0/PhysicalSecurityfortheUtilityIndustry20150210.pdf	This metrics depends on proprietary utility data that is difficult to collect
17	Electricity	Security	Distribution	Number of instances of vandalism or graffiti	Tracks the impact of copper theft and vandalism	Describes how prepared the electric sector is for a physical attack.	≥0 (dimensionless)	Numerical	Process	Accountability	Utility	State Regulator	Lagging	NO	Proprietary utility data	Utility	Monthly	CPUC, 2015. Regulation of Physical Security for the Electric Distribution System, available at http://www.cpuc.ca.gov/NR/rdonlyres/930FCC00-BE2F-4BCF-9B68-2CA2CDC38186/0/PhysicalSecurityfortheUtilityIndustry20150210.pdf	This metrics depends on proprietary utility data that is difficult to collect
18	Electricity	Security	Distribution	Number of problems with access control	Identifies the number of times that an intruder tries to access electric sector facilities for a given utility	Describes how prepared the electric sector is to a physical attack.	≥0 (dimensionless)	Numerical	Process	Accountability	Utility	State Regulator	Lagging	NO	Proprietary utility data	Utility	Monthly	CPUC, 2015. Regulation of Physical Security for the Electric Distribution System, available at http://www.cpuc.ca.gov/NR/rdonlyres/930FCC00-BE2F-4BCF-9B68-2CA2CDC38186/0/PhysicalSecurityfortheUtilityIndustry20150210.pdf	This metrics depends on proprietary utility data that is difficult to collect
19	Electricity	Security	Distribution	Number of malfunctions of security equipment or camera coverage	The number of times that the security system is unable to respond and detect a physical security incident.	Describes how prepared the electric sector is to a physical attack.	≥0 (dimensionless)	Numerical	Process	Accountability	Utility	State Regulator	Lagging	NO	Proprietary utility data	Utility	Monthly	CPUC, 2015. Regulation of Physical Security for the Electric Distribution System, available at http://www.cpuc.ca.gov/NR/rdonlyres/930FCC00-BE2F-4BCF-9B68-2CA2CDC38186/0/PhysicalSecurityfortheUtilityIndustry20150210.pdf	This metrics depends on proprietary utility data that is difficult to collect
20	Electricity	Security	All	Incidents Requiring Manual Cleanup.	Number of Incidents Requiring Manual Cleanup.	Describes how prepared the electric sector is to a cyber attack.		Numerical	Process	Accountability	Utility	State Regulator	Lagging	NO	Proprietary company data	Company-level	Monthly	EPRI, 2015. "Creating Security Metrics for the Electric Sector," available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005947	This metrics depends on proprietary utility data that is difficult to collect

	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 Classific-ation *(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
21	Electricity	Security	All	Mean-Time-to-Fix (MTTF).	Mean-Time-to-Fix (MTTF).	Describes how prepared the electric sector is to a cyber attack.	≥0 (dimensionless)	Numerical	Process	Decision making	Utility	State Regulator	Lagging	NO	Proprietary company data	Company-level	Monthly	EPRI, 2015. "Creating Security Metrics for the Electric Sector," available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005947	This metrics depends on proprietary utility data that is difficult to collect
22	Electricity	Security	All	Cyber Security Workforce Management	Cyber Security Workforce Management	Describes how prepared the electric sector is to a cyber attack.	N/A	Qualitative	Process	Decision making	Utility	State Regulator	Leading	NO	Proprietary company data	Company-level	Monthly	EPRI, 2015. "Creating Security Metrics for the Electric Sector," available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005947	This metrics depends on proprietary utility data that is difficult to collect
23	Electricity	Security	All	Mean Cost to Mitigate Vulnerabilities.	Mean Cost to Mitigate Vulnerabilities.	Describes how prepared the electric sector is to a cyber attack.	≥0 (dimensionless)	Numerical	Process	Account-ability	Utility	State Regulator	Lagging	NO	Proprietary company data	Company-level	Monthly	EPRI, 2015. "Creating Security Metrics for the Electric Sector," available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005947	This metrics depends on proprietary utility data that is difficult to collect
24	Electricity	Security	All	Percent of Changes with Security Review.	Percent of Changes with Security Review.	Describes how prepared the electric sector is to a cyber attack.	≥0 (dimensionless)	Numerical	Process	Decision making	Utility	State Regulator	Lagging	NO	Proprietary company data	Company-level	Monthly	EPRI, 2015. "Creating Security Metrics for the Electric Sector," available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005947	This metrics depends on proprietary utility data that is difficult to collect
25	Electricity	Security	All	Number of outgoing viruses caught at gateway.	Number of outgoing viruses caught at gateway.	Under investigation by EPRI	≥0 (dimensionless)	Numerical	Process	Account-ability	Utility	State Regulator	Lagging	NO	Proprietary company data	Company-level	Monthly	EPRI, 2015. "Creating Security Metrics for the Electric Sector," available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005947	This metrics depends on proprietary utility data that is difficult to collect
26	Electricity	Security	All	Mean Time to Incident Discovery.	Mean Time to Incident Discovery.	Under investigation by EPRI	≥0 (dimensionless)	Numerical	Process	Decision making	Utility	State Regulator	Lagging	NO	Proprietary company data	Company-level	Monthly	EPRI, 2015. "Creating Security Metrics for the Electric Sector," available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005947	This metrics depends on proprietary utility data that is difficult to collect
27	Electricity	Security	All	Number of cyber security skills mastered per employee.	Number of cyber security skills mastered per employee.	Under investigation by EPRI	≥0 (dimensionless)	Numerical	Process	Account-ability	Utility	State Regulator	Lagging	NO	Proprietary company data	Company-level	Monthly	EPRI, 2015. "Creating Security Metrics for the Electric Sector," available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005947	This metrics depends on proprietary utility data that is difficult to collect
28	Electricity	Security	All	Mean Time between Security Incidents.	Mean Time between Security Incidents.	Under investigation by EPRI	≥0 (dimensionless)	Numerical	Process	Decision making	Utility	State Regulator	Lagging	NO	Proprietary company data	Company-level	Monthly	EPRI, 2015. "Creating Security Metrics for the Electric Sector," available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005947	This metrics depends on proprietary utility data that is difficult to collect
29	Electricity	Security	All	Cost of Incidents.	Cost of Incidents.	Under investigation by EPRI	≥0 (dimensionless)	Numerical	Process	Account-ability	Utility	State Regulator	Lagging	NO	Proprietary company data	Company-level	Monthly	EPRI, 2015. "Creating Security Metrics for the Electric Sector," available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005947	This metrics depends on proprietary utility data that is difficult to collect

	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 Classific-ation *(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
30	Electricity	Security	All	Percentage of Systems without Known Severe Vulnerabilities.	Percentage of Systems without Known Severe Vulnerabilities.	Under investigation by EPRI	≥0 (dimensionless)	Numerical	Process	Account-ability	Utility	State Regulator	Lagging	NO	Proprietary company data	Company-level	Monthly	EPRI, 2015. "Creating Security Metrics for the Electric Sector," available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005947	This metrics depends on proprietary utility data that is difficult to collect
31	Electricity	Security	All	Mean Time to Patch.	Mean Time to Patch.	Under investigation by EPRI	≥0 (dimensionless)	Numerical	Process	Account-ability	Utility	State Regulator	Lagging	NO	Proprietary company data	Company-level	Monthly	EPRI, 2015. "Creating Security Metrics for the Electric Sector," available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005947	This metrics depends on proprietary utility data that is difficult to collect
32	Electricity	Security	All	Percentage of Changes with Security Exceptions.	Percentage of Changes with Security Exceptions.	Under investigation by EPRI	≥0 (dimensionless)	Numerical	Process	Accountability	Utility	State Regulator	Lagging	NO	Proprietary company data	Company-level	Monthly	EPRI, 2015. "Creating Security Metrics for the Electric Sector," available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005947	This metrics depends on proprietary utility data that is difficult to collect
33	Electricity	Security	All	Percentage of Applications Subject to Risk Assessment.	Percentage of Applications Subject to Risk Assessment.	Under investigation by EPRI	≥0 (dimensionless)	Numerical	Process	Account-ability	Utility	State Regulator	Lagging	NO	Proprietary company data	Company-level	Monthly	EPRI, 2015. "Creating Security Metrics for the Electric Sector," available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005947	This metrics depends on proprietary utility data that is difficult to collect
34	Electricity	Security	All	Information Security Budget Allocation.	Information Security Budget Allocation.	Under investigation by EPRI	≥0 (dimensionless)	Numerical	Process	Decision making	Utility	State Regulator	Lagging	NO	Proprietary company data	Company-level	Monthly	EPRI, 2015. "Creating Security Metrics for the Electric Sector," available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005947	This metrics depends on proprietary utility data that is difficult to collect
35	Electricity	Security	All	Compliance or Coverage of Information Security Practice	Compliance or Coverage of Information Security Practice	Under investigation by EPRI	N/A	Qualitative	Process	Decision making	Utility	State Regulator	Lagging	NO	Proprietary company data	Company-level	Monthly	EPRI, 2015. "Creating Security Metrics for the Electric Sector," available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005947	This metrics depends on proprietary utility data that is difficult to collect
36	Electricity	Security	All	Number of protective programs implemented in a given year	Number of protective programs implemented in a given year	Describes how prepared the electric sector is to a physical attack.	≥0 (dimensionless)	Numerical	Process	Account-ability	Federal (DHS), Utility	State Regulator	Lagging	NO	Proprietary company data	Company-level	Annual	DHS, 2006. National Infrastructure Protection Plan, available at https://www.dhs.gov/xlibrary/assets/NIPP_Plan_noApps.pdf	This metrics depends on proprietary utility data that is difficult to collect
37	Electricity	Security	All	Level of investment of protective programs	Level of investment of protective programs	Describes how prepared the electric sector is to a physical attack.	≥0 (dimensionless)	Numerical	Process	Account-ability	Federal (DHS), Utility	State Regulator	Lagging	NO	Proprietary company data	Company-level	Annual	DHS, 2006. National Infrastructure Protection Plan, available at https://www.dhs.gov/xlibrary/assets/NIPP_Plan_noApps.pdf	This metrics depends on proprietary utility data that is difficult to collect
38	Electricity	Security	All	Number of detection systems installed at faciities	Number of detection systems installed at faciities	Describes how prepared the electric sector is to a physical attack.	≥0 (dimensionless)	Numerical	Process	Accountability	Federal (DHS), Utility	State Regulator	Lagging	NO	Proprietary company data	Company-level	Annual	DHS, 2006. National Infrastructure Protection Plan, available at https://www.dhs.gov/xlibrary/assets/NIPP_Plan_noApps.pdf	This metrics depends on proprietary utility data that is difficult to collect

	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 Classific-ation (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
39	Electricity	Security	All	Proportion of facility's workforce that has completed security training	Proportion of facility's workforce that has completed security training	Describes how prepared the electric sector is to a physical attack.	≥0 (dimensionless)	Numerical	Process	Account-ability	Federal (DHS), Utility	State Regulator	Lagging	NO	Proprietary company data	Company-level	Annual	DHS, 2006. National Infrastructure Protection Plan, available at https://www.dhs.gov/xlibrary/assets/NIPP_Plan_noApps.pdf	This metrics depends on proprietary utility data that is difficult to collect
40	Electricity	Security	All	Level of response to a data call for asset information	Level of response to a data call for asset information	Describes how prepared the electric sector is to a physical attack.	N/A	Qualitative	Process	Decision making	Federal (DHS), Utility	State Regulator	Leading	NO	Proprietary company data	Company-level	Annual	DHS, 2006. National Infrastructure Protection Plan, available at https://www.dhs.gov/xlibrary/assets/NIPP_Plan_noApps.pdf	This metrics depends on proprietary utility data that is difficult to collect
41	Electricity	Security	All	Reduction of risk from one year to another	Reduction of risk from one year to another	Describes how prepared the electric sector is to a physical attack.	≥0 (dimensionless)	Numerical	Outcome	Decision making	Federal (DHS), Utility	State Regulator	Leading	NO	Proprietary company data	Company-level	Annual	DHS, 2006. National Infrastructure Protection Plan, available at https://www.dhs.gov/xlibrary/assets/NIPP_Plan_noApps.pdf	This metrics depends on proprietary utility data that is difficult to collect
42	Electricity	Security	All	Overall risk mitigation achieved nationally	Overall risk mitigation achieved nationally	Describes how prepared the electric sector is to a physical attack.	≥0 (dimensionless)	Numerical	Outcome	Decision making	Federal (DHS), Utility	State Regulator	Leading	NO	Proprietary company data	Company-level	Annual	DHS, 2006. National Infrastructure Protection Plan, available at https://www.dhs.gov/xlibrary/assets/NIPP_Plan_noApps.pdf	This metrics depends on proprietary utility data that is difficult to collect
43	Electricity	Security	All	Risk Management	Considers actions to (1) establish cybersecurity risk management strategy, (2) manage cybersecurity risk, (3) management activities	Describes how prepared the electric sector is to a cyber attack.	MIL1 to MIL3	Qualitative	Process	Account-ability	Utility		Lagging	NO	Proprietary company data	Company-level	Annual	DOE, 2014. Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2), available at http://energy.gov/sites/prod/files/2014/02/f7/ES-C2M2-v1-1-Feb2014.pdf	This metrics depends on proprietary utility data that is difficult to collect
44	Electricity	Security	All	Asset, Change, and Configuration Management	Considers actions to (1) manage asset inventory, (2) manage asset configuration, (3) manage changes to assets, (4) management activities	Describes how prepared the electric sector is to a cyber attack.	MIL1 to MIL3	Qualitative	Process	Account-ability	Utility		Lagging	NO	Proprietary company data	Company-level	Annual	DOE, 2014. Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2), available at http://energy.gov/sites/prod/files/2014/02/f7/ES-C2M2-v1-1-Feb2014.pdf	This metrics depends on proprietary utility data that is difficult to collect
45	Electricity	Security	All	Identity and Access Management	Addresses (1) establish and maintain identities, (2) control access, (3) management activities	Describes how prepared the electric sector is to a cyber attack.	MIL1 to MIL3	Qualitative	Process	Account-ability	Utility		Leading	NO	Proprietary company data	Company-level	Annual	DOE, 2014. Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2), available at http://energy.gov/sites/prod/files/2014/02/f7/ES-C2M2-v1-1-Feb2014.pdf	This metrics depends on proprietary utility data that is difficult to collect
46	Electricity	Security	All	Threat and Vulnerability Management	Addresses activities to (1) identify and respond to threats, (2) reduce cybersecurity vulnerabilities, (3) management activities	Describes how prepared the electric sector is to a cyber attack.	MIL1 to MIL3	Qualitative	Process	Account-ability	Utility		Leading	NO	Proprietary company data	Company-level	Annual	DOE, 2014. Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2), available at http://energy.gov/sites/prod/files/2014/02/f7/ES-C2M2-v1-1-Feb2014.pdf	This metrics depends on proprietary utility data that is difficult to collect
47	Electricity	Security	All	Situational Awareness	Considers actions to (1) perform logging, (2) perform monitoring, (3) establish and maintain a common operating picture	Describes how prepared the electric sector is to a cyber attack.	MIL1 to MIL3	Qualitative	Process	Account-ability	Utility		Leading	NO	Proprietary company data	Company-level	Annual	DOE, 2014. Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2), available at http://energy.gov/sites/prod/files/2014/02/f7/ES-C2M2-v1-1-Feb2014.pdf	This metrics depends on proprietary utility data that is difficult to collect

	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 Classific-ation *(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
48	Electricity	Security	All	Information Sharing and Communications	Addresses actions to (1) share cybersecurity information, (2) management activities	Describes how prepared the electric sector is to a cyber attack.	MIL1 to MIL3	Qualitative	Process	Account-ability	Utility		Leading	NO	Proprietary company data	Company-level	Annual	DOE, 2014. Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2), available at http://energy.gov/sites/prod/files/2014/02/f7/ES-C2M2-v1-1-Feb2014.pdf	This metrics depends on proprietary utility data that is difficult to collect
49	Electricity	Security	All	Event and Incident Response, Continuity of Operations	Considers activities to (1) detect cybersecurity events, (2) escalate cybersecurity events and declare incidents, (3) respond to incidents and escalated cybersecurity events, (4) plan for continuity	Describes how prepared the electric sector is to a cyber attack.	MIL1 to MIL3	Qualitative	Process	Account-ability	Utility		Leading	NO	Proprietary company data	Company-level	Annual	DOE, 2014. Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2), available at http://energy.gov/sites/prod/files/2014/02/f7/ES-C2M2-v1-1-Feb2014.pdf	This metrics depends on proprietary utility data that is difficult to collect
50	Electricity	Security	All	Supply Chain and External Dependencies Management	Addresses activities to (1) identify dependencies, (2) manage dependency risk	Describes how prepared the electric sector is to a cyber attack.	MIL1 to MIL3	Qualitative	Process	Account-ability	Utility		Leading	NO	Proprietary company data	Company-level	Annual	DOE, 2014. Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2), available at http://energy.gov/sites/prod/files/2014/02/f7/ES-C2M2-v1-1-Feb2014.pdf	This metrics depends on proprietary utility data that is difficult to collect
51	Electricity	Security	All	Workforce Management	Considers actions to (1) assign cybersecurity responsibilities, (2) control the workforce life cycle, (3) develop cybersecurity workforce, (4) increase cybersecurity awareness	Describes how prepared the electric sector is to a cyber attack.	MIL1 to MIL3	Qualitative	Process	Account-ability	Utility		Leading	NO	Proprietary company data	Company-level	Annual	DOE, 2014. Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2), available at http://energy.gov/sites/prod/files/2014/02/f7/ES-C2M2-v1-1-Feb2014.pdf	This metrics depends on proprietary utility data that is difficult to collect
52	Electricity	Security	All	Cybersecurity Program Management	Evaluates actions to (1) establish cybersecurity program strategy, (2) sponsor cybersecurity program, (3) establish and maintain cybersecurity architecture, (4) perform secure software development	Describes how prepared the electric sector is to a cyber attack.	MIL1 to MIL3	Qualitative	Process	Account-ability	Utility		Leading	NO	Proprietary company data	Company-level	Annual	DOE, 2014. Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2), available at http://energy.gov/sites/prod/files/2014/02/f7/ES-C2M2-v1-1-Feb2014.pdf	This metrics depends on proprietary utility data that is difficult to collect

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