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

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Summary

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> **Reliability**
>
> The ability to maintain 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.

The Grid Modernization Laboratory Consortium (GMLC) Metrics team: 1) Developed new metrics for distribution reliability, which account for the economic cost of power interruptions to customers, and implemented them in partnership with the American Public Power Association (APPA); 2) Participated in the development and implementation of improvements to interconnection-wide metrics on bulk power system reliability, which will be reported annually in the North American Electric Reliability Corporation (NERC) State of Reliability report; and 3) Conducted a demonstration of the use of metrics for probabilistic transmission planning and reviewed them with the Electricity Reliability Council of Texas (ERCOT), ISO New England (ISO-NE), and Idaho Power Company (IPC).

S.1. Motivation

The reliability of the electric power system has long been a focus of study. 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, of which the GMLC Metrics Team focused on the following three:

First, household, firm/industrial, and society's dependence on electricity have grown and expectations for reliability have increased. Our understanding of the economic consequences that arise when electric service is interrupted has also increased. It is appropriate to take explicit account of these economic consequences when making decisions to maintain or improve reliability. Newly developed tools, such as the Department of Energy's (DOE) Interruption Cost Estimate (ICE) Calculator, are available to support incorporation of this information in reliability decision-making. Yet, traditional reliability metrics, such as System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), cannot—in their current form—be used in conjunction with these tools.

Second, restructuring of the electricity industry has led to distinct federal and state regulatory regimes for overseeing reliability. The federal regime focuses on oversight of the operation of the bulk electric power system (generally, above 100 kV). The state regime focuses on oversight of the operation of local distribution systems (generally, less than 100 kV). Current system-wide reliability metrics, such as SAIDI and SAIFI, do not identify whether the cause of power interruptions originates from the bulk electric power system or from within the local distribution system. Hence, they cannot be used with precision to inform the decisions that federal and state regulators must make in overseeing the reliability of the portions of the electric power system that they regulate. NERC has begun to develop a new system-wide measure of the reliability of the bulk power system called the Severity Risk Index (SRI), which it publishes annually in the State of Reliability report. In its current form, however, the SRI does not account for two important aspects of the manner by which the bulk power systems of the US are operated: A) there are three interconnections; each is operated (and hence performs) independently of the other two, yet there is only a single SRI calculated for the entire US); B) the SRI is composed of a combination of three static measures of reliability and does not account for the dynamic interactions among these measures that makes some combinations much more challenging for reliability than others.

Third, uncertainty around the future generation mix and composition of loads has grown. The growth in renewable sources of generation whose output varies and hence cannot be dispatched in the traditional sense particularly introduces specific new types of uncertainties into utility planning and operations. Current planning techniques are challenged to take these uncertainties into account and lead to misleading conclusions. Probabilistic planning techniques can treat these new types of uncertainty explicitly and consistently in reliability planning and thereby improve these decision-making processes. Currently, their application is nascent and formal metrics to assess their performance have not been adopted by the transmission planning community.

S.2. Outcomes/Impact

S.2.1 New Distribution Reliability Metrics, Developed with APPA

The APPA eReliability Tracker is an online tool available to APPA's members for the purpose of recording and analyzing utility reliability information.[4] A principal use case is automated development of standard distribution reliability metrics, such as SAIDI and SAIFI, based on information entered by a participating utility. Information is typically entered at the circuit level (as opposed to for the whole utility), which facilitates the automated generation of circuit-level reliability reports, such as lists of the worst (or best) performing circuits. These reports are used by the utilities to help prioritize reliability-enhancing investments of improvements in practices.

The ICE Calculator is a publicly available, online tool that allows users to estimate the economic costs borne by customers due to interruptions of their electric service.[5] The analytic engine underlying the ICE Calculator is a series of econometrically estimated equations that relate the economic cost to features of the customer experiencing the interruptions (e.g., whether they are a residential, small commercial or industrial, or large commercial or industrial customer) and of the interruption (e.g., how long the interruption lasts). The equations were developed through analyses conducted on a pool of all available past utility-sponsored customer surveys on the value of lost load.[6]

The GMLC team provided the underlying equations in the ICE Calculator to APPA, which then programmed them into the eReliability Tracker. APPA then developed automated reports on the economic costs to customers of power interruptions as a standard offering of eReliability Tracker. The team participated in reviews of developmental versions of these reports and made suggestions for improvement to the information (e.g., metrics) presented.

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[4] https://www.publicpower.org/reliability-tracking

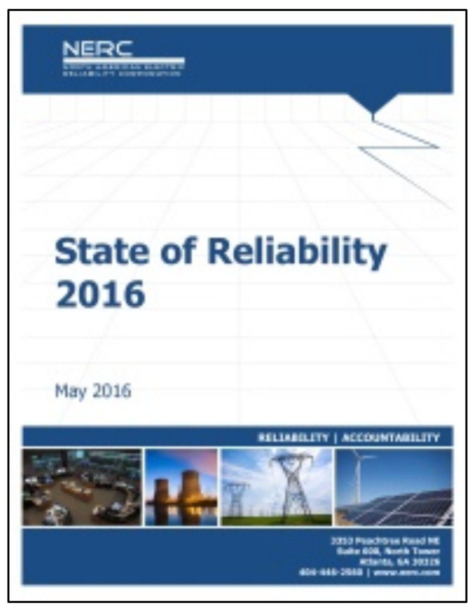
[5] https://icecalculator.com/home

[6] Sullivan MJ, J Schellenberg, and M Blundell. 2015. *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States.* Lawrence Berkeley National Laboratory, Berkeley, CA. January. LBNL-6941E. http://emp.lbl.gov/sites/all/files/lbnl-6941e.pdf

At the time of this writing (Winter 2018-19), APPA reports that approximately 250 utilities are routinely receiving these reports.[7] The team plans to continue work with APPA in 2019 to review how utilities are using the reports and suggest enhancements to further extend and ease their membership's use of the tool.

S.2.2 Improved Bulk Power System Reliability Metrics, Developed through NERC

NERC, through its Performance Analysis Subcommittee, has for many years compiled and published both leading and lagging metrics on aspects of bulk power system reliability in the annual State of Reliability report.[8] The report features an overall metric of reliability of the bulk power system, called the Severity Risk Index (SRI).[9] The SRI is calculated for each day of the year. It enables a ranking of the overall reliability of the bulk power system on daily basis. The GMLC Metrics Team was invited to join the NERC Performance Analysis Subcommittee with a specific request to participate in ongoing refinements to the SRI and the preparation of the State of Reliability report. To date (Winter 2018-19), the team has been involved in two enhancements to the SRI.



First, rather than calculate a single, daily SRI for the US as a whole, the Performance Analysis Subcommittee is working toward calculating a separate daily SRI for each of the three US interconnections. The motivation for this effort is the recognition that each interconnection operates independently of the other on an essentially standalone basis. The reliability of each interconnection does not affect the reliability of its neighboring interconnections.

As part of this effort, the Performance Analysis Subcommittee is also evaluating options to improve the loss of load element that is a key input to the calculation of the SRI. It had been long recognized that the information provided by the Institute of Electrical and Electronics Engineers (IEEE) Distribution Reliability Working Group, while the best available, was not a precise nor comprehensive measure of the loss of load due to causes originating from the bulk power system. First, the definition of loss of supply does not describe losses

[7] Personal communication. Alex Hoffman, APPA, 8 November 2018.

[8] https://www.nerc.com/pa/RAPA/PA/Pages/default.aspx

[9] https://www.nerc.com/comm/PC/Performance%20Analysis%20Subcommittee%20PAS%202013/SRI%20Enhancement%20Whitepaper.pdf

due solely to causes originating from the bulk power system; it also includes losses originating from sub-transmission systems (which are outside the jurisdiction of NERC/Federal Energy Regulatory Commission [FERC]). Second, because the information developed by IEEE is provided voluntarily by some but not all utilities, the information may not be representative of an entire interconnection. This fact contributed to the reason why an interconnection-specific SRI could not be calculated for the 2018 State of Reliability. It was found there was no information on loss of load from utilities within one interconnection, and efforts to go back to utilities in this interconnection to collect the needed information took place too late in the process for inclusion in the 2018 State of Reliability report.

Going forward, the team is also in discussions with leading academics to explore potential enhancements to the SRI to account for the dynamic relationships among generation availability, transmission availability, and loss of load. Currently, these three elements of the SRI are calculated independently from one another and then combined with one another through the use of static weights that are invariant across all the days of the year. The team seeks to develop a systematic means for replacing these weights dynamically by taking into explicit consideration time-varying, interdependencies among the three underlying elements (and potentially other elements, as well).

S.2.3 Metrics for Probabilistic Transmission Planning, Demonstrated for ERCOT, ISO-NE, and IPC

The GMLC team performed a scoping study on transmission system reliability metrics that reviewed existing transmission planning activities, major challenges, and reliability metrics used by ERCOT, ISO-NE, and Idaho Power Company (IPC).[10] The scoping study also included a discussion of ongoing or planned activities on probabilistic planning applications and metrics by these utilities. In their current planning activities, almost all of the metrics they use are deterministic. The sole exceptions are those used in resource adequacy studies, e.g., loss of load expectation.

The scoping study showed that, although these utilities are facing different types of challenges, all of them recognized that the uncertainties they encounter in daily operations were growing and can no longer be ignored. In particular, uncertainties that affected specific planning metrics, but which were currently unaccounted for, were identified and discussed.

One example is the metrics used for transmission contingency analysis. Currently, the analysis of these contingencies is binary: a reliability criterion either is or is not exceeded. This form of analysis does not consider 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 of various contingencies with respect to one another. Yet, understanding the frequency and severity of various contingencies is essential for assessing the risks contingencies pose to the system and hence the priorities to assign to potential remedies. The scoping study showed that deterministic metrics such as loss-of-load and voltage violations can be enhanced by associating each with a probabilistic distribution. The probabilistic distribution is determined by the distributions of frequencies and durations of the individual contingencies of grid components such as generators, transmission circuits, as well as renewable generation that are used in the deterministic calculations.

In the scoping study, the sources and modeling of uncertainties for various planning studies, the existence and availability of data sources needed for calculating the probabilistic metrics, and the availability of the

[10] Yue, M. 2018. A Scoping Study on Transmission System Reliability Metrics Performed for GMLC Project 1.1 Foundational Metrics. Brookhaven National Laboratory. May.

tools that can be used for the calculation were identified. A brief discussion was also provided on development of the aforementioned probabilistic enhancement to existing deterministic metrics.[11]

[11] Note that the perspective taken by the scoping study is that transmission planning authorities would use both deterministic and probabilistic reliability metrics simultaneously, not one or the other. Using both metrics takes advantage of the strengths of both types of metrics. Also note that the focus of this study was on transmission planning. These methods could also be extended to operational planning but pursuit of this is beyond the scope of this initial, scoping study.

Acknowledgments

The Grid Metrics Reliability Team is grateful for the strong partnership it has established with the American Public Power Association and the North American Electric Reliability Corporation, and for the timely advice and support provided by Electric Reliability Council of Texas, Idaho Power Company, and ISO New England.

Acronyms and Abbreviations

APPA	American Public Power Association
DOE	U.S. Department of Energy
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas, Inc.
FERC	Federal Energy Regulatory Commission
GADS	Generation Availability Data System
GMLC	Grid Modernization Laboratory Consortium
GMLC1.1	Grid Modernization Laboratory Consortium Project Metrics Analysis
ICE	Interruption Cost Estimate
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
ISO	independent system operator
LBNL	Lawrence Berkeley National Laboratory
MAIFI	Momentary Average Interruption Frequency Index
MYPP	Multi-Year Program Plan
NERC	North American Electric Reliability Corporation
RMS	root mean square
RTO	regional transmission organization
SAIDI	Systems Average Interruption Duration Index
SAIFI	Systems Average Interruption Frequency Index
TADS	Transmission Availability Data System

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1.0 Introduction

1.1 Project Background and Motivation

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

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) 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, Office of Energy Efficiency and Renewable Energy, and Office of Energy Policy and Systems Analysis—by revealing and quantifying the current state and the evolution over time of the nation's electric infrastructure.

This project started in April 2016 and ended in March 2019.

1.2 Metric Categories Definitions

The MYPP uses the term attribute to describe the characteristics of the power grid. In this report, we use the term "metric areas" or metric categories. Metrics are physical or economic considerations 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 distribution systems, measuring reliability focuses on interruption of the delivery of electricity in sufficient quantities and of sufficient quality to meet electricity users' needs for (or applications of) electricity. For the bulk power system, measuring reliability focuses separately on both the operational (current or near-term	We are developing new metrics of distribution reliability, which account for the economic cost of power interruptions to customers, with the American Public Power Agency (APPA). Developing new metrics of bulk power system reliability for use in the North American Electricity Reliability Corporation's (NERC's) Annual State of Reliability Report.

Metric Categories	Definitions	Focus Areas under GMLC 1.1
	conditions) and planning (longer term) time horizons.	We are demonstrating the use of probabilistic transmission planning metrics with the Electric Reliability Council of Texas (ERCOT) and Idaho Power.
Resiliency	Can prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions, including the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents (Obama 2013).	We apply a consequence-based approach that defines a process using resilience goals to a set of defined hazards. This approach provides the information needed to prioritize investments for resilience improvements.
Flexibility	Respond to future uncertainties that may stress the system in the short term and require the system to adapt over the long term. Short-term flexibility to address operational and economic uncertainties that are likely to stress the system or affect costs. Long-term flexibility to adapt to economic variabilities and technological uncertainties that may alter the system.	We focus on flexibility of the bulk power system needed to accommodate 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. In Years 2 and 3, we also explore water metrics.
Affordability	Provide electric services at a cost that does not exceed customer willingness and ability to pay for those services (Taft and Becker-Dippman 2014).	We document established investment cost-effectiveness metrics and focus our research on emerging customer cost-burden metrics.
Security	Prevent external threats and malicious attacks from occurring and affecting system operation. Maintain and operate the system with limited reliance on supplies (primarily raw materials) from potentially unstable or hostile countries. Reduce the risk to critical infrastructure by physical means or defense cyber measures to intrusions, attacks, or the effects of natural or man-made disasters (Obama 2013).	We develop metrics to help utilities evaluate their physical security posture and inform decision-making and investment.

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

2.0 Objectives

The objective of the reliability metrics research and analysis conducted through GMLC1.1 is to develop new, refine existing, or demonstrate new applications of existing electric power system reliability metrics. The overall objective served by these activities is to improve the quality of decision-making for reliability-related planning, operations, and regulation decisions.

3.0 Approach

The approach consisted of three parts. First, we reviewed and categorized existing electric power system reliability metrics. Second, we identified three selected needs and purposes that would be served by new metrics, refinements to existing metrics, or new applications that could be supported by existing reliability metrics. Third, we worked in partnership with a key or leading industry stakeholder to pursue the research. A key industry stakeholder is one for whom there are no peers, such as the North American Electric Reliability Corporation (NERC). A leading industry stakeholder is one for whom there are peers, such as one of the seven US regional transmission organizations/independent system operators (RTOs/ISOs). In some instances, we were able to advance the research to the point where it could be demonstrated.

3.1 Stakeholder and Partners

As noted, in each instance the research was conducted in partnership with a key or leading industry stakeholder. The purpose was to confirm both the need for and usefulness of the research. This was accomplished by formulating and executing (including modifying in midstream) the research in direct response to the articulated needs of the partner. The goal was to conduct research the partner could and would use directly for their existing needs; that is, in a real-world business setting. We felt doing so would provide the most direct or tangible means possible for demonstrating the value of the research. In working with a key industry partner, such a demonstration was expected to provide a direct pathway for adoption or institutionalization of the research in the partner's future related activities. In working with a leading industry partner, such a demonstration was expected to provide a direct means for adoption by the partner, as above, but also a tangible means for adoption by their peers in industry with similar needs.

3.2 Users of This Research

Three partnerships were pursued through this research. As noted above, the type of partner we worked with defines the scope of users of the research.

One partnership was with a key industry partner for whom there is no US peer. NERC is the Federal Energy Regulatory Commission (FERC)-designated electricity reliability organization with responsibilities for the development and enforcement of mandatory reliability rules for the bulk power system. The user of the reliability metrics research we conducted, therefore, is principally NERC itself. Nevertheless, the reliability of the bulk power system is a material concern for most if not all aspects of the North American electric power systems. Users of the research range from government officials, such as FERC and DOE, to utilities and state public utility commissions.

Two partnerships were with leading industry partners for whom there are US peers. APPA is the trade organization for publicly owned utilities in the US and some of its protectorates (e.g., Puerto Rico). The peer users of the reliability research conducted with APPA include all utilities (publicly owned, investor owned, and cooperatively owned) as well as their regulatory or oversight bodies (such as state public utility commissions or governing boards).

ERCOT is a regional transmission organization or RTO for the electrically independent Texas Interconnection. Its direct peers are the other six RTO/ISOs in the US and so to a first approximation, these RTO/ISOs are also potential users of the research. Nevertheless, the reliability metrics research we conducted focuses on aspects of transmission planning that are not unique to RTO/ISOs. In principle, the users of the research include all transmission planning organizations that are conducting planning for bulk power systems that incorporate significant amounts of variable, renewable generation sources.

4.0 Outcomes

4.1 Definition

Reliability refers to the ability to maintain 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.

4.2 Existing Metrics and Their Maturity

The reliability of the electric power system has long been a focus of study. Many highly mature metrics are in widespread use for this area. The purposes they serve remain important today. 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.[12][13] They also include reporting on individual large events, such as those that are reported to NERC, in accordance with Standard EOP-004, and to DOE, using form OE-417.[14] Lagging metrics also include those specifically related to 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 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 Area Control Error Limit) and frequency response performance of balancing authorities (e.g., Balancing Authority Frequency Response).

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[12] SAIDI measures the total number of minutes on average each customer is without electric service for a given time period. It is defined as follows: $\mathrm{SAIDI} = \frac{\sum \text{Customer Interruption Durations}}{\sum \text{Total Number of Customers Served}}$ (1)
Higher values of SAIDI correspond to more minutes on average of interruption experienced by all customers 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 on average each customer experiences a power interruption. It is defined as follows: $\mathrm{SAIFI} = \frac{\sum \text{Total Number of Interruptions}}{\sum \text{Total Number of Customers Served}}$ (2)
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.

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

[14] 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.

Lagging metrics can be applied to both the electric system as a whole or to elements (or equipment) within the system. All of the above examples are lagging metrics applied to the electric power system as a whole. Examples of lagging ultimate metrics for equipment are equipment outages and equipment misoperation. 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 4.1 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.

4.3 Emerging and Future Metrics

As noted, there already many highly mature metrics are in widespread use for this area. However, there are also rapidly growing needs for new, complementary reliability metrics of which the GMLC Metrics Team focused on the following three:

First, household, firm/industrial, and society's dependence on electricity have grown and expectations for reliability have increased. Our understanding of the economic consequences that arise when electric service is interrupted has also increased. It is appropriate to take explicit account of these economic consequences when making decisions to maintain or improve reliability. Newly developed tools, such as DOE's Interruption Cost Estimate (ICE) Calculator, are available to support incorporation of this information in reliability decision-making. Yet, traditional reliability metrics, such as SAIDI and SAIFI, cannot in their current form be used in conjunction with these tools.

Second, restructuring of the electricity industry has led to distinct federal and state regulatory regimes for overseeing reliability. The federal regime focuses on oversight of the operation of the bulk electric power system (generally, above 100 kV). The state regime focuses on oversight of the operation of local distribution systems (generally, less than 100 kV). Current system-wide reliability metrics, such as SAIDI and SAIFI, do not identify whether the cause of power interruptions originates from the bulk electric power system or from within the local distribution system. Hence, they cannot be used with precision to inform the decisions that federal and state regulators must make in overseeing the reliability of the portions of the electric power system they regulate. NERC has begun to develop a new system-wide measure of the reliability of the bulk power system called the Severity Risk Index (SRI), which it publishes annually in the State of Reliability report. In its current form, however, the SRI does not account for two important aspects of the manner by which the bulk power systems of the US are operated: A) there are three interconnections; each is operated (and hence performs) independently of the other two, yet there is only a single SRI calculated for the entire US); B) the SRI is composed of a combination of three static measures of reliability and does not account for the dynamic interactions among these measures, which makes some combinations much more challenging for reliability than others.

Third, uncertainty around the future generation mix and composition of loads has grown. The growth in renewable sources of generation whose output varies and hence cannot be dispatched in the traditional sense particularly introduces specific new types of uncertainties into utility planning and operations. Current planning techniques cannot take these uncertainties into account and lead to misleading conclusions. Probabilistic planning techniques can treat these new types of uncertainty explicitly and consistently in reliability planning and thereby improve these decision-making processes. Currently, their application is nascent and formal metrics to assess their performance have not been adopted by the transmission planning community.

Table 4.1. 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, Momentary Average Interruption Frequency Index (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 to assess evaluation of economic impacts on customers.** Annual utility level metrics do not account for customer-owned standby generation or uninterruptible power supply systems
		Intermediate: Operational performance in compliance with NERC standards	Monthly CPS1 and Balancing Authority Area Control Error Limit scores; Daily Interconnected Reliability Limit (IROL) and System Operating Limit 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/misoperation rates; total outage duration (generators)	Generator/Transmission Operators; NERC Generation Availability Data System (GADS) and Transmission Availability Data System (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

Type	Source	Example	Metrics	Granularity/Data Sources; Availability	Concerns (bold = focus of GMLC Reliability Task)
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 loss-of-load expectations; % 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

4.3.1 Improving Distribution System Reliability 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 of customers have experienced a power interruption and for how long in order to understand the economic costs that power interruptions impose on them (see Footnote 1). This task was conducted in partnership with APPA and developed new metrics that enable direct consideration of the cost of power interruptions to customers to support more informed 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. Yet information on the actual duration and number of interruptions is essential for understanding the economic impacts of these interruptions on customers. Capturing this information requires further de-aggregating or unpacking of averages and expressing the information 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 that record the start time, duration, and restoration of power to customers affected by power interruptions (advanced meter infrastructure 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), and federal agencies (e.g., 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 fostered these engagements by working directly with APPA to develop and demonstrate metrics that capture these currently under-analyzed economic aspects of power interruptions. The development of new metrics was enabled by integrating the calculations that underlie Lawrence Berkeley National Laboratory's (LBNL's) Interruption Cost Estimate (ICE) Calculator into APPA's eReliability Tracker.

The ICE Calculator is a publicly available online tool that allows users to estimate the economic costs borne by customers due to interruptions of their electric service.[15] The analytic engine underlying the ICE Calculator is a series of econometrically estimated equations that relate economic costs to features of the customer experiencing interruptions (e.g., whether they are a residential, small commercial or industrial, or large commercial or industrial customer) and of the interruption (e.g., how long the interruption lasts).

[15] https://icecalculator.com/home

The equations were developed through analyses conducted on a pool of all available past utility-sponsored customer surveys on the value of lost load.[16]

The eReliability Tracker is an online tool that is available to APPA members for the purpose of recording and analyzing utility reliability information.[17] A principal use case is automated development of standard distribution reliability metrics, such as SAIDI and SAIFI, based on information entered by a participating utility. Information is typically entered at the circuit level (as opposed to the whole utility), which facilitates the automated generation of circuit-level reliability reports, such as lists of the worst (or best) performing circuits. These reports are used by the utilities to help prioritize reliability-enhancing investments of improvements in practices.

The GMLC team provided the underlying LBNL equations in the ICE Calculator to APPA, which then programmed them into the eReliability Tracker. APPA then developed automated reports on the economic costs to customers of power interruptions as a standard offering of the eReliability Tracker. The team participated in reviews of developmental versions of these reports and made suggestions for improvement to the information (e.g., metrics) presented.

At the time of this writing (late Winter 2019), APPA reports that approximately 250 utilities are routinely receiving these reports.[18] The team plans to work with APPA in 2019 to review how utilities are using the reports and suggest enhancements to further extend and ease their membership's use of the tool. One area we have discussed with APPA is use of the tool to help plan and prioritize distribution investments by taking into direct account the customer interruption costs that might be avoided by these investments.

4.3.2 Improving Bulk Power System Reliability Metrics

NERC has for many years compiled and published both leading and lagging metrics on aspects of bulk power system reliability. The Long-term Resource Adequacy Assessment, which NERC publishes annually, is a long-standing compilation of forward-looking (i.e., leading) metrics on resource adequacy for each regional entity.[19] The principal metric is generation reserve margin.

Starting in 2012, NERC has published an annual compilation of retrospective (i.e., lagging) reliability metrics in the State of Reliability.[20] While responsibilities for developing the information used are dispersed among NERC staff and various NERC committees and subcommittees, the NERC Performance Analysis Subcommittee has final responsibility for receiving, reviewing, and assembling this information into the annual report.

In addition, the NERC Performance Analysis Subcommittee was charged with and has developed an overall metric of reliability of the bulk power system, called the SRI.[21] This index is calculated for each day of the year. It enables a ranking of the overall reliability of the bulk power system on a daily basis.

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[16] Sullivan, M., J. Schellenberg, and M. Blundell. 2015. *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States,* Lawrence Berkeley National Laboratory, Berkeley, CA. January. LBNL-6941E. http://emp.lbl.gov/sites/all/files/lbnl-6941e.pdf
[17] https://www.publicpower.org/reliability-tracking
[18] Personal communication. Alex Hoffman, APPA, 8 November 2018.
[19] https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx
[20] https://www.nerc.com/pa/RAPA/PA/Pages/default.aspx
[21] https://www.nerc.com/comm/PC/Performance%20Analysis%20Subcommittee%20PAS%202013/SRI%20Enhancement%20Whitepaper.pdf

In its current formulation, the SRI is comprised of the weighted sum of three distinct underlying metrics. The first of these metrics is developed from NERC GADS. It measures the fraction of the nation's generation fleet that was not available to supply power on each day of the year because it was on an unplanned or forced outage that day. The second is developed from NERC TADS. Similar to the GADS metric, it measures the amount of transmission that is not available on a daily basis, again due to unplanned or forced outages. The third metric seeks to measure how much load is not served due to interruptions of power caused by the bulk power system. This metric is provided through an agreement with the IEEE Distribution Reliability Working Group, which conducts an annual voluntary survey of distribution utilities who provide daily SAIDI and SAIFI information. The utilities provide this information in a manner that distinguishes between unplanned interruptions due to causes originating within the distribution system and those due to the loss of supply (to the distribution system). The latter value is used to calculate the SRI.

The GMLC was invited to join the NERC Performance Analysis Subcommittee with a specific request to participate in ongoing refinements to the SRI and the preparation of the State of Reliability report. To date, the team has been involved in two enhancements to the SRI.

Starting in 2018, the Performance Analysis Subcommittee began efforts to develop the daily SRI on an interconnection-specific basis. That is, rather than calculate a single daily SRI for the United States as a whole, the Performance Analysis Subcommittee sought to calculate a separate daily SRI for each of the three US interconnections. The motivation for this effort was the recognition that each interconnection essentially operates on a standalone basis. The reliability of each interconnection does not affect the reliability of its neighboring interconnections.

In addition, the Performance Analysis Subcommittee is beginning efforts to improve the loss-of-load element in the SRI. It had been long recognized the information provided by the IEEE Distribution Reliability Working Group, while the best available, was not a precise nor comprehensive measure of the loss of load due to causes originating from the bulk power system. First, the definition of loss of supply does not describe losses due solely to causes originating from the bulk power system. In some instances, it may include losses originating from portions of the transmission systems that are not part of the bulk power system (e.g., subtransmission facilities), and hence not under the jurisdiction of NERC. Second, because the information developed by IEEE is provided voluntarily by some but not all utilities, the information may not be representative of an entire interconnection. This contributed to the reason why an interconnection-specific SRI could not be calculated for the 2018 State of Reliability. There was no information on loss of load from utilities within one interconnection and efforts to go back to utilities in this interconnection to collect the needed information took place too late in the process for preparing the State of Reliability report.

The GMLC team participated in both of these SRI-related activities of the NERC Performance Analysis Committee. Going forward, the team is also in discussions with leading academics to explore potential enhancements to the SRI to account for the relationship among generation availability, transmission availability, and loss of load in a more integrated fashion. Currently, these three elements of the SRI are calculated independently from one another and then combined through use of static weights that are invariant across all days of the year. The team seeks to develop a systematic means for replacing these weights dynamically by taking into explicit consideration time varying interdependencies among the three underlying elements (and potentially other elements).

4.3.3 Probabilistic Enhancement of Transmission Planning Reliability 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 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, such as the less predictable patterns of generation from renewables. On the other hand, transmission planning and expansion have been relying on and will continue to rely on such metrics for making decisions. Therefore, utilities do not necessarily have to develop new planning metrics but need the probabilistic enhancement to existing metrics to extract addition information.

A scoping study on transmission system reliability metrics has been performed by reviewing the existing transmission planning activities, major challenges, and reliability metrics used in ERCOT, New England ISO, and Idaho Power Company (IPC).[22] The scoping study also includes a discussion of ongoing or planned activities on probabilistic planning applications and metrics by these utilities. In their current planning activities, almost all of the metrics used are deterministic; the sole exceptions are those used in resource adequacy studies, e.g., loss-of-load expectations.

The scoping study shows that, although these utilities are facing different types of challenges, all of them recognize the uncertainties encountered in daily operations are growing and can no longer be ignored. A significant amount of effort has been spent attempting to understand and capture these uncertainties in both long-term and operational planning of transmission systems. The existing planning metrics used by the utilities for compliance with NERC's transmission planning standards are reviewed and summarized in this study. The metrics being used include loss-of-load probability or expectation (used to measure generation adequacy and usually probabilistic by considering the load profile and scheduled and random generation unit outages), short-circuit current, thermal capacity rating, voltage level (pre-and post-contingency), damping ratio, etc. Uncertainties that potentially affect different planning metrics but are unaccounted for are discussed for each of the metrics.

One example is the metrics for transmission contingency analysis. Contingency analysis evaluates system security (i.e., system responses under disturbances by taking preventive and corrective actions). The impacts of contingencies on the system with respect to element capacity ratings are measured by metrics 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 account for 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 are essential for assessing the risks that contingencies pose to the system and hence the priorities of potential remedies. The deterministic metrics such as loss-of-load and voltage violation with probabilistic metrics can be enhanced by associating each of the metrics with a probabilistic distribution determined by the distributions of frequencies and durations of the individual contingencies of grid components such as generators and transmission circuits as well as renewable generation.

The scoping study identified the sources and modeling of uncertainties for various planning studies, the existence and availability of data sources needed for calculating the probabilistic metrics, and the availability of tools that can be used for the calculation. The scoping study discussed how probabilistic

[22] Yue, M. 2018. A Scoping Study on Transmission System Reliability Metrics Performed for GMLC Project 1.1 Foundational Metrics. Brookhaven National Laboratory. May.

enhancements or complements could be developed for deterministic metrics by rigorously modeling the uncertainties that underlie them.

For example, short-circuit current is a deterministic metric that is used in short-circuit analysis. It is used by planners to specify the ratings required for protection devices and other equipment in the power system. Generally speaking, utility planners model a bolted, three-phase fault to yield the maximum short-circuit current, which is then used to examine the most severe operating condition to which grid components may be subjected (and expected to withstand).

Yet when a fault occurs, the short-circuit current may be affected by a variety of factors, including the pre-fault voltages on the system, the components of the system experiencing the fault, and the location of the fault. In addition, there are also now new sources of short-circuit current—distributed energy resources (DERs)—that must also be taken into consideration in planning studies. The contributions of these new sources depend on their sizes, capabilities, and locations.

The challenge for planners is that all of these factors are, to an extent, random nature; that is, they cannot be known in advance. Yet the modeling tools planners rely on to calculate short-circuit current are deterministic. In their current formulation, the tools all rely on static assumptions regarding each of these factors.

The scoping study outlines an enhancement to this traditional study practice in which all the factors are modeled as continuous or discrete random variables. The enhanced metrics for short-circuit current consist of distributions for these metrics, as determined by the various uncertainties that underlie each contributing factor.

The scoping study clarifies that, as envisioned, transmission planning authorities would rely on both deterministic and probabilistic reliability metrics as complements to one another—thereby taking advantage of the strengths of both types of metrics. Finally, note that the focus of the scoping study was on transmission planning. This method and approach can be extended to other operational planning topics, but pursuit of them was beyond the scope of this initial scoping study.

4.4 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.

4.4.1 Asset, Distribution, Bulk Power Level

Improved distribution system metrics will apply to utility distribution systems as a whole as well as to subregions or even individual feeders within a utility service territory. Improved bulk power system metrics will apply primarily to each of the three US interconnected bulk power systems (Eastern, Western, and Texas). 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.

4.4.2 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 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.

4.4.3 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 standalone 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., New York ISO and ERCOT).

4.4.4 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. Probabilistic transmission planning metrics would generally be applicable at the regional level. See discussion above under state level; regional transmission planning entities in the US generally span multiple states.

4.4.5 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 United States, two of which 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 a whole (unless one sought to study interconnecting the three US interconnections and, at the same time, disconnecting them from Canada and Mexico).

4.4.6 Other Level

Not applicable.

4.5 Use Cases for Metrics

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

With respect to improving distribution system reliability metrics, we co-developed and demonstrated with APPA distribution-level metrics that capture the economic impact of power interruptions on utility customers.

With respect to improving bulk power system reliability metrics, we are co-developing and demonstrating with the NERC Performance Analysis Subcommittee improved metrics starting with enhancements to the SRI metric that is reported annually by NERC in the State of Reliability report.

With respect to probabilistic transmission planning metrics, we worked with ERCOT and Idaho Power to identify how probabilistic contingency analysis can be performed to calculate probabilistic metrics. ERCOT provided 1 year of historical 5-minute-interval generation data of individual wind plants for this purpose. Renewable sources are 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. As an example, in addition to a complete loss of generation, under- or over-generation of renewable generators caused by intermittency also have to be explicitly modeled. A case study shows that the intermittency induced outages can be modeled and fitted into the probabilistic contingency analysis framework.[23]

4.6 Links to Other Metrics

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 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) 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 and 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.

[23] M. Yue, S. W. Kang, C. Jin, and J. Matevosjana, "An Investigation of Potential Intermittency Induced Outage Modes for Wind Generation," Proceedings of PMAPS 2018.

5.0 Next Steps

With respect to distribution reliability metrics that account for the economic costs of power interruptions to customers, we would like to both continue refinement of appropriate metrics with APPA and seek broader industry adoption of these metrics and the economic-based reliability planning principles that they enable.

With respect to bulk power system reliability metrics developed on an interconnection-specific basis, we would like to continue our work with the NERC Performance Analysis Subcommittee to continue to improve the underlying data used to calculate the SRI and explore more dynamic means for using the underlying data toward the development of an enhanced SRI-like metric in the future.

With respect to probabilistic transmission reliability planning metrics, we would like to perform a study to answer one of the most frequently asked questions: how to make use of the probabilistic metrics in the utility decision-making process?

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Appendix A

Metrics Inventory

Appendix A

Metrics Inventory

A.1 Reliability 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)*	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 Root Mean Square (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

	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)***	**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**
																			utility 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 CEMI 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 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)***	**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.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
REL 14	A Scoping Study on Transmission System Reliability Metrics Performed for GMLC Project 1.1 Foundational Metrics (M. Yue)

Appendix B

Value of Metrics

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Value of Metrics

Based on engagements with stakeholders that were conducted at the initiation of this project, the following specific values were reported. It is important to recognize that these engagements took place prior to the project activities described in the body of this report. In each instance, they were relied on to inform and direct the project activities conducted by the grid metrics team.

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

- APPA has had long-time interest in maintaining reliable electric systems and 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 it can be very helpful to 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 ICE Calculator originally funded by DOE and LBNL, is to provide an interface that enables the combination of actual outage data collected by utilities with the publicly 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 was released in December 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. This will develop 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 work 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 these customers might experience from an outage that would require distinct definitions of the value of reliability.

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

- The metrics we currently have are suitable for today's system, but not for tomorrow's. At what point tomorrow comes we cannot predict, but we know that better metrics will need to be available before they are needed.

- The overall goal of this collaborative effort is to try to enhance the metrics that are in the report led by the 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. This research will determine how this can 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 new metrics that will complement SRI and address things SRI cannot tell us.
- This work effort is likely the start of a long-term collaborative and ground-up exploratory engagement with NERC. The approach being taken in GMLC1.1 is very different from earlier approaches. Previously, LBNL developed a new tool or new technique and now we are seeking to apply it to NERC's data and use it to calculate the value of metrics we 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.

Probabilistic transmission planning metrics: ERCOT and Idaho Power recognize the need for and value of probabilistic planning metrics, which can be achieved via a probabilistic enhancement of existing deterministic metrics. Probabilistic metrics accounts for uncertainties better than their deterministic counterparts. Frequencies and duration for contingencies of different grid components are inherently different and need to be captured. In addition, the uncertainties associated with renewables pose an even bigger challenge in decision-making for utility transmission expansion. Developing probabilistic metrics offers a feasible solution to address the uncertainty issue.

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