Risks and Mitigations for Losing EMS Functions
Reference Document – Version 2

Introduction
An Energy Management System (EMS) is a system of computer-aided tools used by system operators to monitor, control, and optimize the performance of generation and/or transmission systems. An EMS, which encompasses Supervisory Control and Data Acquisition (SCADA), telecommunications and real-time reliability support tools, is vital for situational awareness as well as making and implementing well-informed operating decisions.

The purpose of this reference document is to identify and discuss the risk of losing EMS functions, analyze the causes of EMS events reported through the Electric Reliability Organization (ERO) Event Analysis Process (EAP), and share mitigation strategies to reduce these risks.

The ERO EAP is an effective tool for analyzing the reported events and identifying risks. Through the EAP, the registered entities, with the help of NERC and the Regions, identify the root and contributing causes of EMS events and share this information with industry through lessons learned publications. Additionally, the NERC Monitoring and Situational Awareness Conference is a collaborative effort of industry and vendors. Experts gather to discuss these lessons learned and share best practices to minimize the frequency and duration of EMS outages. The conference takes place annually in the fall.

The following are concluded in the reference document:

- Software and communications failure are major contributors to the loss of EMS functions.
- The loss of EMS functions has not led to the loss of generation, transmission lines, or customer load.
- Mitigating actions have been effectively applied during EMS events to manage risks within acceptable levels.
- The EAP is used to analyze, track, and trend these outages. Lessons Learned and best practices are shared with industry to improve overall EMS performance.
- The NERC Monitoring and Situational Awareness Conference provides a forum for vendor involvement to share knowledge and collaborate with industry to minimize the frequency and duration of EMS outages.

---

1 This reference document is provided for guidance and does not reflect binding norms or mandatory requirements.
What is an Energy Management System and why is it important?

An EMS is a system of computer-aided tools used by System Operators to monitor, control, and optimize the performance of the generation and/or transmission system. An EMS, which encompasses SCADA, telecommunications and real-time reliability support tools, is vital for situational awareness as well as making and implementing well-informed operating decisions. An EMS consists of both hardware and software. The hardware part of an EMS consists of remote terminal units (RTUs) at the substations, computer servers at the data centers, the telecommunications systems both wired and wireless, plus the system control centers including all the computers used to monitor and control the Bulk Electric System (BES). The software component of an EMS consists of application programs for the data acquisition, control, alarming, real-time calculations, and network analysis of power systems including state estimation, contingency analysis.

The primary objective of an EMS is to provide situational awareness to the System Operators\(^2\) and allow remote control of devices to provide secure and stable operation of the BES. Situational awareness includes, but is not limited to, the following:

- The ability to monitor/control the frequency within the System Operator’s area
- The ability to monitor/control the status (open or closed) of switching devices, plus real and reactive power flows on generators, BES tie-lines and transmission facilities within the system operator’s areas
- The ability to monitor/control voltage and reactive resources
- The ability to monitor the status of applicable EMS applications such as Real-Time Contingency Analysis (RTCA) and/or alarm management

Using this information pertaining to situational awareness, the system operators can make decisions that affect the reliability and resiliency of the BES. Generation can be dispatched or taken off-line to prevent overloads or improve the voltage in an area. Capacitor banks, shunt devices, synchronous condensers or other voltage-controlling tools can be utilized to maintain voltage limits. Transmission breakers and remote-controlled switches can be opened or closed as needed to address real-time and contingency conditions.

In an EMS, application programs are run in a real-time or in an extended real-time environment to keep the power system in a secure operating condition. These EMS applications include SCADA, Alarm Processing, Automatic Generation Control (AGC), Network Applications (including State Estimation), Power Flow, Contingency Analysis or Security Analysis (CA or SA), and Data Historians, among others. Figure 1 shows a simplified EMS configuration.

\(^2\) NERC Reliability Guideline “Situational Awareness for the System Operator”
Inter Control Center Protocol (ICCP): ICCP has been standardized under the IEC 60870-6 specifications and allows the exchange of real-time and historical power system monitoring and control data, including measured values, data quality codes, scheduling data, energy accounting data, and operator messages. Data exchange can occur over wide area networks between utility control centers, utilities, power pools, regional control centers, and non-utility generators.

Supervisory Control and Data Acquisition (SCADA): SCADA is a category of software application programs for process control and the gathering of data in real-time from remote locations in order to control devices and monitor conditions. SCADA sends and receives telemetered data between the RTU or ICCP link and the control center. Control signals are sent from the operator’s desk at the control center back to the field to change the status of devices (e.g., open or close breakers) or adjust generation.

Remote Terminal Unit (RTU): An RTU is a microprocessor-controlled electronic device that interfaces devices in the physical world to a distributed control system or SCADA system by transmitting telemetry data to a master system, and by using messages from the master supervisory system to control connected devices.

Front End Processor (FEP): An FEP interfaces the host computer to a number of networks, such as systems network architecture, or a number of peripheral devices, such as RTU’s, terminals, disk units, printers and tape units. Data is transferred between the host computer and the front end processor using a high-speed parallel interface. The front end processor communicates with peripheral devices using slower serial interfaces, usually also through communication networks. The purpose is to off-load from the host computer the work of managing the peripheral devices, transmitting and receiving messages, packet assembly and disassembly, error detection, and error correction.
**Automatic Generation Control (AGC):** An AGC is an application for adjusting the power output of multiple generators at different power plants in response to changes in interchange, load, generation, and frequency error. The AGC software uses real-time data such as frequency, actual generation, tie-line load flows, and plant controller status to determine generation changes.

**State Estimator (SE):** An SE is an application that calculates the current state of the electrical system (the voltage magnitudes and angles at every bus) using a network model and telemetered measurements. The purpose is to provide a consistent base case for use by other network applications programs such as Power Flow and Contingency Analysis. While SCADA relies on direct telemetered values from the RTUs, the SE is able to calculate and predict non-metered values to provide additional situational awareness to the system operators.

**Real-time Contingency Analysis (RTCA):** An RTCA is an application used to predict electrical system conditions after simulating specific contingencies. It relies on a base case from a SE or Power Flow case.

In an EMS, voltage magnitudes and power flows over the lines are continuously monitored through SCADA, SE, and RTCA to check for voltage/thermal exceedances. The EMS system is programmed with limits on the BES equipment. These limits are used with Alarm Processing to send visual and audio alarms to the system operators when monitored quantities are approaching or exceeding the threshold of an operating limit. AGC computes a Balancing Area’s Area Control Error (ACE) from interchange and frequency data. ACE determines whether a system is in balance or adjustments need to be made to generation. AGC software also determines the required output for generating resources while observing energy balance and frequency control by sending set-points to generators. The scheduled tie line power flows are maintained by adjusting the real power output of the AGC controlled generators to accommodate fluctuating load demands.

The typical dependency between main EMS applications is illustrated in **Figure 2**.

![Figure 2: Typical dependency between main EMS Applications](image-url)
The data flows between EMS functions shown in Figure 2 are described below:

- **ICCP Data** (between ICCP Application and SCADA): Real-time and historical power system monitoring and control data, including measured values, data quality codes, scheduling data, energy accounting data, generator set-point controls and operator messages.

- **RTU Data** (between FEP Application and SCADA): Data from substation devices and commands to substation devices. This data includes the following:
  - Measured Values
  - Position Indication
  - Positioning Commands
  - Alarms

- **Path 1** (from SCADA to AGC): Telemetered status data and analogue value data that includes the following:
  - Area frequency
  - Tie line MW
  - Generator unit online/offline
  - Generator unit control local or remote
  - Generator unit MW output
  - Generator unit MW set-point feedback
  - Generator unit MW limits

- **Path 2** (from AGC to SCADA): New set-point controls calculated by AGC.

- **Path 3** (from SCADA to SE): The data typically consists of the following:
  - Breaker statuses (open or closed)
  - Switch statuses (open or closed)
  - Transformer tap settings
  - MW flow measurements
  - MVAR flow measurements
  - Voltage magnitude measurements
  - Current magnitude measurements
  - Phase angle difference measurements
  - High-Voltage Direct Current (HVDC) operating modes
  - Tagging statuses
- Special measurements defined by users
- Path 4 (from AGC to SE): the data typically consists of the following:
  - Generator unit control (local or remote)
  - Generator unit MW output
  - Generator unit MW limits
- Path 5 (from SE to RTCA): A base case solution typically consists of the following:
  - System topology
  - Voltage magnitudes and angles at each bus
  - Transformer tap settings
  - Generator unit control statuses
  - Generator unit MW limits
  - HVDC operating modes
  - VAR statuses

Analysis of Loss of EMS Functions
This section of the reference document will identify and discuss the risks of losing EMS functions, analyze reasons for the loss of EMS functions based on EMS events reported by 161 NERC Compliance Registries (NCRs) between October 2013 and April 2019, and present mitigation strategies that reduce the risk when one or more EMS functions are temporarily lost or disabled.

Risks of Loss of EMS Functions
Situational awareness is necessary to maintain reliability, anticipate events and respond appropriately when or before they occur. Without the appropriate tools and data, system operators may have degraded situational awareness for making decisions that ensure reliability for a given condition of the BES. Certain essential functional capabilities must be in place with up-to-date information for staff to make informed decisions. An essential component of monitoring and situational awareness is the availability of information when needed. Unexpected outages of functions, or planned outages without appropriate coordination or oversight, can leave system operators with impaired visibility. While failure of a decision-support tool has not directly led to the loss of generation, transmission lines, or customer load, such failures may hinder the decision-making capabilities of the system operators during a disturbance. NERC has analyzed data and identified that short-term outages of tools and monitoring systems are not uncommon, and the industry is committed to reducing the frequency and duration of these types of events.

The BES reliability risk due to EMS function failures varies depending on the function that is lost and the duration of that outage.
**Loss of SCADA**
The loss of SCADA would likely be the most impactful EMS failure. The system operators would not have indication of the status of devices or key data points such as MW, MVAR, current, voltage, or frequency from the RTUs. Furthermore, the system operators would not be able to open and close breakers or switches remotely from the control center. SCADA data feeds AGC, SE/RTCA applications. Loss of quality data would compromise their functionality.

**Loss of ICCP**
The loss of ICCP would disrupt the information that is shared between Transmission Operators (TOP), Balancing Authorities (BA), Generation Operators (GOP), and Reliability Coordinators (RC). The RCs rely on information from its BAs and TOPs to monitor the wider area, and an ICCP outage may remove real-time updates to the affected section of the model.

**Loss of SE**
The loss of SE would involve the system operators losing the situational awareness not directly provided by the SCADA system. While the system operators would still have SCADA which would provide control and indication of all telemetered devices, the loss of SE would eliminate other key data values that help the system operators monitor the system, plus limit the predictive analysis that the EMS provides.

**Loss of RTCA**
The loss of RTCA may prevent alerting the system operators when the next contingency presents a potential reliability issue, compromising situational awareness and reliability, and increasing the complexity of performing Real Time Assessments.

**Reasons for Loss of EMS Functions**
There were 521 EMS events reported between October 2013 and April 2019 through the EAP which will be further discussed in the following section. These include the loss of SCADA, ICCP, RTU, AGC, SE, RTCA, or a combination of these functions for 30 or more continuous minutes. Figure 3 shows the number of reported EMS events per loss of EMS functions. It was determined that losing state estimator and/or RTCA and losing the ability to monitor or control are the two most common failures, encompassing approximately 80 percent of reported EMS events.
Figure 3: Number of Reported EMS Events per Loss of EMS Functions

The reported EMS events can be grouped by the following attributes:

- **Software**: software defects, modeling issues, database corruption, memory issues, etc.
- **Communications**: devices issues (e.g., RTU failure, FEP failure, fiber failure, network router failure,) or changes made (e.g., firewall failure) or less than adequate system interactions (e.g., bad telemetered data quality).
- **Facility**: loss of power to the control center or data center, fire alarm, AC failure, etc.
- **Maintenance**: system upgrades, job-scoping, change-management, risk identification and other themes such as testing in a controlled environment and implementing the change (e.g., system/software configuration or settings failure, patch change, or implementation that causes EMS functions to crash).

Table 1 shows the breakdown of the attributes in each EMS function failure. Software and communications are significant contributors to loss of EMS functions.

<table>
<thead>
<tr>
<th>Failure</th>
<th>Software</th>
<th>Communications</th>
<th>Maintenance</th>
<th>Facility</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Loss of SE/RTCA</td>
<td>164</td>
<td>40</td>
<td>25</td>
<td>3</td>
<td>232</td>
</tr>
<tr>
<td>Loss of ability to monitor or control</td>
<td>32</td>
<td>48</td>
<td>45</td>
<td>57</td>
<td>182</td>
</tr>
<tr>
<td>Loss of ICCP</td>
<td>0</td>
<td>47</td>
<td>2</td>
<td>2</td>
<td>51</td>
</tr>
<tr>
<td>Loss of RTU</td>
<td>2</td>
<td>35</td>
<td>4</td>
<td>3</td>
<td>44</td>
</tr>
<tr>
<td>Loss of AGC</td>
<td>9</td>
<td>2</td>
<td>1</td>
<td>0</td>
<td>12</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>207</strong></td>
<td><strong>172</strong></td>
<td><strong>77</strong></td>
<td><strong>65</strong></td>
<td><strong>521</strong></td>
</tr>
</tbody>
</table>
The model of the electrical grid is critical for SE/RTCA calculation. The model includes the detailed topology of the system along with the appropriate parameters for the equipment within the system. These parameters can include impedances, line and voltage limits, transformer ratios and controls, generator limits, and reactive capabilities, among others. Therefore, a wrong or not-up-to-date model (e.g. wrong topology, inaccurate line impedances and transformer tap positions, not-up-to-date external network, etc.) can lead to loss of SE/RTCA. Figure 4 illustrates that modeling issue is a major contributor to loss of SE/RTCA.

![Figure 4: Contributors to Loss of SE/RTCA](image)

**Mitigations for the Risk of Loss of EMS Functions**

In all of the reported events from October 2013 to April 2019, there has been no EMS event that directly led to the loss of generation, transmission lines, or customer load. The 521 reported EMS events from October 2013 to April 2019 were approximately 70 minutes in duration on average. The following mitigations have been effectively applied to manage the risks within acceptable levels:

- Enhanced system restoration plans that include drills and training on the procedures, plus real-life practice implementing the procedures.
- Overlapping coverage of situational awareness with RC’s and neighboring TOPs and BAs so that the system is being continuously monitored by additional entities outside of that immediate footprint. This is further strengthened by additional ICCP data points from generators and tie-lines that can provide visibility.
  - The RC notifies adjacent RCs, TOPs, and BAs within its RC Area when it loses essential Real-time tools capability. Once notified by an RC of problems with the RC Real-time tools, RC Area TOPs and BAs, or adjacent RC(s) will report any detected BES outages or abnormal BES conditions.

---

including abnormal conditions related to generation, loads or tie-line flows or SOL exceedances, to their (or the affected) RC until normal monitoring capabilities are restored. During this same time period, TOPs and BAs also report any significant Real-time or post-contingent overloads or voltage limit deviations to their RC.

- With an extended and continued loss of essential real-time tools, a BA/TOP notifies their RC and their neighboring entities (known impacted interconnected entities) of the tool problem or degradation being experienced as soon as practical, but generally within 30 minutes of the loss. The notification generally includes the following:
  - A single point-of-contact and preferred method of communication
  - Extent of the real time tool loss and systems impacted (to understand the magnitude)
  - Plan and status for corrective actions to restore lost functionality
  - Any requested assistance and plan for maintaining system monitoring and control
  - Estimated time for restoration of functionality (if known)
  - An agreed upon schedule for periodic updates

- Offline tools (studies) that can be used for analyzing contingencies plus other contingency-analysis including day-ahead studies, seasonal and standing operating guides, and system operator training.
- Enhanced preventive controls that include limits and bounds on external data where the SE/CA can converge around the erroneous data.
- Backup tools and functionality that include backup EMS systems, backup control centers, and other additional redundancy.
- Collaboration with vendors to build comprehensive testing procedures and/or troubleshoot the cause of the failure in order to minimize the system recovery time.
- Manning substations during EMS events so that system operators and field personnel can take action as needed (e.g., open/close breakers), verify status of devices, plus verify power flows and voltages.
- Internally defined conservative operations procedures used during EMS events (e.g., no switching, additional monitoring, manning substations, and asking neighbors for assistance).
- Different mechanisms have been built or set up for notification:
  - Normal phone communication capabilities (e.g., phones, cell phones, satellite, radio)
  - Emergency Hot Line System or “blast call” system
  - NERC Reliability Coordinator Information System (RCIS)\(^4\),
  - WECC-wide Messaging System\(^5\)

---

\(^4\) The system the RCs use to post messages and share operating information in Real-time is called the Reliability Coordinator Information System (RCIS).

\(^5\) AESO, BC Hydro RC, and RC West will use the Grid Messaging System (GMS); SPP will use the Reliability Communication Tool (RComm).
FERC and NERC conducted a study – Planning Restoration Absent SCADA or EMS (PRASE report)\(^6\) – that focused on the potential impact of the loss of EMS, SCADA, or ICCP functionality on system restoration, and the manner in which such impact could be mitigated. The objective of the study was to assess entities’ system restoration plan steps in the absence of EMS, SCADA, and/or ICCP data, and identify viable resources, methods or practices that would expedite system restoration despite the loss of such systems. The following was concluded in the PRASE report:

- All volunteer registered entities have made significant investments in their SCADA and EMS infrastructures, including leveraging redundancies to increase availability and functionality.
- All volunteer registered entities would remain capable of executing their restoration plan without SCADA/EMS availability.
- Five recommendations are provided for all entities responsible for system restoration, stated in the following:
  - Planning for backup communications measures
  - Planning for personnel support during system restoration absent SCADA
  - Planning backup power supplies for an extended period of time
  - Analysis tools for system restoration.
  - Incorporating loss of SCADA or EMS scenarios in system restoration training

TOPs and RCs are requested to perform Real-time Assessments per NERC Standards TOP-001-3, Requirement R13, and IRO-008-2, Requirement R4. A compliance implementation guidance\(^7\) (CIG) has been endorsed by ERO Enterprise to assist NERC registered entities in establishing a common understanding of the practices and processes surrounding the completion of a Real-time Assessment. This guidance also offers examples for managing Real-time Assessments with or without the use of RTCA tools or other support applications.

To avoid single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data for real time monitoring and Real-time Assessments, the redundant and diversely routed data exchange infrastructure within the primary Control Center and associated tests for redundant functionality are required by NERC Reliability Standards TOP-001-4, Requirements R20, R21, R23, and R24 and IRO-002-5 Requirements R2 and R3. The NERC Data Exchange Infrastructure Requirements Task Force developed a CIG\(^8\) from the perspective of the Reliability Standards. The CIG discusses data exchange infrastructure reference models and associated examples of redundant functionality tests and identifies

\(^6\) “FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans”

\(^7\) “TOP-001-3 R13 and IRO-008-2 R4 Real Time Assessments (OC)”

\(^8\) “TOP-001-4 and IRO-002-5 Data Exchange Infrastructure and Testing (OC)”
ways to avoid single points of failure in primary Control Center data exchange infrastructure that could halt the flow of real-time data, which in turn could result in loss of situational awareness.

**Event Analysis Process (EAP)**

The ERO EAP was launched in October 2010. The ERO EAP is intended to promote a structured and consistent approach to performing event analyses in North America. Through the ERO EAP, the ERO strives to develop a culture of reliability excellence that promotes aggressive self-critical review and analysis of operations, planning, and critical infrastructure protection (CIP) processes. The ERO EAP also serves an integral function as a learning opportunity for the industry by providing insight and guidance by identifying and disseminating valuable information to owners, operators, and users of the bulk power system who enable improved and more reliable operation. EMS events are defined in Cat 1h⁹ events.

1h. Loss of monitoring or control at a Control Center such that it significantly affects the entity’s ability to make operating decisions for 30 continuous minutes or more.

Some examples that should be considered for EA reporting include but are not limited to the following:

1. Loss of operator ability to remotely monitor or control BES elements
2. Loss of communications from SCADA Remote Terminal Units (RTU)
3. Unavailability of ICCP links, which reduces BES visibility
4. Loss of the ability to remotely monitor and control generating units via AGC
5. Unacceptable state estimator or real time contingency analysis solutions

The process involves identifying what happened, why it happened, and what can be done to prevent reoccurrence. Identification of the sequence of events answers the “what happened” question and determination of the root cause of an event answers the “why” question. It also allows for events to have cause codes or characteristics and attributes assigned, which can then be used by the Event Analysis Subcommittee (EAS) to identify trends. Trends may identify the need to take action, such as a NERC Alert, or may support changes to Reliability Standards.

More than 180 entities reported EMS events and participated in the ERO EAP since 2010. To-date, more than 150 Lessons Learned¹⁰ documents have been posted and shared with the industry, with more than 50 Lessons Learned specifically dealing with EMS-related issues. The ERO EAP has proven to be an effective method for analyzing EMS outages and the industry has readily participated without a NERC Reliability Standard. Focusing on the root and contributing causes helps to determine the appropriate mitigating actions, and these lessons are shared with industry. The information gathered is disseminated and shared with industry at the annual NERC Monitoring and Situational Awareness Conference, highlighted below.

---

⁹ For the latest category definition, please refer to [http://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx](http://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx)

NERC Monitoring and Situational Awareness Conference

As the ERO, NERC is committed to continuous learning and improvement of BPS reliability. Beginning in 2013, NERC has hosted an annual Monitoring and Situational Awareness Conference. The conference creates awareness of common problems observed by utilities, promotes an exchange of ideas, shares good industry practices, and brings together expertise from various utilities and vendors in a collaborative, educational atmosphere. The ERO EAP captures lessons learned and common trends for EMS outages and makes them available to industry by creating awareness and involving stakeholders in a collaborative process, therefore, many challenges can be effectively mitigated. The ultimate goal is to minimize the outages, in terms of both EMS outage duration and frequency; with the objective of maintaining the highest levels of situational awareness.

The themes of the conferences since 2013 are listed below, and the presentations are available on NERC’s website:\n
<table>
<thead>
<tr>
<th>Year</th>
<th>Theme</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>Industry practices for reducing the EMS outages, alleviating risks involved when outages occur and maintaining situational awareness</td>
</tr>
<tr>
<td>2014</td>
<td>Sustaining EMS Reliability</td>
</tr>
<tr>
<td>2015</td>
<td>The tools and monitoring capabilities of both EMS/SCADA systems and third party software that gives system operator’s the real-time “bird’s eye” view of system conditions</td>
</tr>
<tr>
<td>2016</td>
<td>EMS resiliency with an emphasis on the capacity to recover quickly from difficulties</td>
</tr>
<tr>
<td>2017</td>
<td>EMS Solution Quality (Modeling and Real-time Assessment)</td>
</tr>
<tr>
<td>2018</td>
<td>The Evolution of EMS Systems</td>
</tr>
<tr>
<td>2019</td>
<td>Solutions for Emerging Changes</td>
</tr>
</tbody>
</table>

Conclusion

This reference document describes EMS functions and components. Its primary contribution is to identify and discuss BES reliability risks due to the loss of EMS functions, analyze causes of loss of EMS functions based on EMS events reported between October 2013 and April 2019, and present mitigations used by industry to reduce the number and impact of EMS events. This reference document also highlights the work the ERO EAP does with analyzing these events and sharing this information with industry. These lessons learned and trends are also shared at the annual NERC Monitoring and Situational Awareness Conference. This conference is a collaboration with industry and vendors to minimize the duration and frequency of EMS outages and their potential reliability impacts to the BES.

The following can be concluded:

- Software and communication failures are significant contributors to the loss of EMS functions.
- The loss of EMS functions has not directly led to the loss of generation, transmission lines, or customer load. However, it is important to note that the loss of EMS functionality has contributed to cascading events because it limited system operators’ capability to maintain situational awareness.

\[11 \text{ http://www.nerc.com/pa/rrm/Resources/Pages/Conferences-and-Workshops.aspx} \]
• The ERO EAP is an effective process for analyzing these risks by identifying the root and contributing causes and sharing this information with industry.

• “Good utility practice” mitigations have been effectively applied during EMS events to manage risks within acceptable levels.

• Enhanced system restoration plans have been effectively applied. The plans include drills and training on the procedures, plus real-life practice implementing the procedures.

• Overlapping coverage of situational awareness with the RC’s and neighboring TOPs and BAs so that the system is being continuously monitored by additional entities outside of that immediate footprint. This is further strengthened by additional ICCP data points from generators and tie-lines that can provide visibility.

• The utilities have effectively utilized offline tools (studies) for analyzing contingencies plus other contingency-analysis including day-ahead studies, seasonal and standing operating guides, and system operator training.

• The utilities have implemented enhanced preventive controls that include limits and bounds on external data where the SE/CA can converge around the erroneous data.

• The utilities have implemented backup tools and functionality that include backup EMS systems, backup control centers, and other additional redundancy.

• Collaboration with vendors to build comprehensive testing procedures and/or troubleshoot the cause of the failure in order to minimize the system recovery time.

• Manning substations during EMS events so that system operators and field personnel can take action as needed (open/close breakers), verify status of devices, plus verify power flows and voltages.

• Internally defined conservative operations procedures used during EMS events (no switching, additional monitoring, manning substations, asking neighbors for assistance)

• Several layers of communications have been implemented as needed (e.g., phones, cell phones, satellite, radio, RCIS, WECC-wide Messaging System).

Considering the average outage time (70 minutes) of the 521 events reported by 161 NCRs from October 2013 to April 2019, it was observed that the actual EMS availability was 99.99%12 during the term. Therefore, the mitigation strategies described above have been proven to work effectively. To further

12 Considering the average outage time (70 minutes) of the 521 reported events from October 2013 to April 2019,

\[
\text{Total down time (in minutes)} = 521 \text{ events} \times 70 \text{ minutes/event} = 36470 \text{ minute.}
\]

Assuming that any distinct NCRs submitting a report regarding EMS outage has an EMS system,

\[
\text{Total time (in minutes)} = 161 \text{ entities} \times 60 \text{ min/hr} \times 24 \text{hr/day} \times 2038 \text{ days} = 472489920 \text{ minutes.}
\]

Therefore,

\[
\text{System Availability} = \frac{(\text{Total Time} - \text{Total Downtime})}{\text{Total Time}} = \frac{(472489920 - 36470)}{472489920} = 0.9999228 \sim 99.99\%
\]
enhance EMS availability, ERO will work directly with the stake-holders to maintain the EAP momentum, continue data gathering, track and trend the risk, conduct analysis, develop solutions, and share the information.