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Oak Ridge National Laboratory NERC MISOPS

Energy Science and Technology Directorate

Electrification and Energy Infrastructures Division

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Investigation of Misoperations on the North American BPS

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ABSTRACT

This investigation was commissioned by the Office of Electricity of the Department of Energy in response to reviewing the NERC State of Reliability report. The study is an attempt to proactively address electric utility industry needs.

> "Monitoring, analyzing, and tracking trends in Protection System Misoperations are critical to improve BES reliability. Historically, Protection System Misoperations have exacerbated the severity of most cascading power outages." [1]

The NERC misoperations data shows that unnecessary trips are by far the leading category of reported misoperations and that a majority of misoperations are those of line protection packages. A significant number of misoperations are tied to microprocessor relays. The leading causes of reported misoperations are due to incorrect settings, relay failures/malfunctions and communication failures.

1. CONTEXT, BACKGROUND AND AUTHORITY

This section will provide the background and context to why misoperation data is collected, how it became mandatory and how the various organizations involved derived their authority to require the collection of misoperation data.

1.1 NORTHEAST BLACKOUT OF 1965 & THE FORMATION OF NERC

Prior to 1965 the electricity industry operations followed North American Power Systems Interconnection Committee (NAPSIC) criteria and guides for reliable operations. There were also some regional reliability planning guides. These criteria and guides were maintained and practiced on a voluntary basis. [2]

On November 9, 1965, one of the largest blackouts in United States history took place in the northeast starting in Ontario, Canada which led to several heavily loaded transmission lines to fail. [3] The cascading event eventually put the state of New York in the dark along with parts of: Connecticut, Rhode Island, Massachusetts, Vermont, New Hampshire, New Jersey, Pennsylvania, and Ontario Canada. Approximately 30 million people were without electricity. The Federal Power Commission performed an investigation into the outage and found that the event initiated with a faulty setting in a protection relay that tripped a 230kV transmission line. [4] The event started with a relay mis-operation.

As a result, the Federal Power Commission (FPC) formed an Advisory Committee on Reliability of Electric Bulk Power Supply to identify measures to prevent major outages. The committee published the findings in a three-volume report to the president titled, "Prevention of Power Failures: An Analysis and Recommendations Pertaining to the Northeast Failure and the Reliability of U.S. Power Systems" [4]

In response to the blackout, the Northeast Power Coordinating Council (NPCC) was formed in 1966 with an eye to improving coordination, planning and operation among all the utilities in the Northeast region. NPCC became the first reliability council in North America. Shortly thereafter, eight other regional reliability councils formed across North America. Legislation was introduced in Congress to form a council on power coordination titled "U.S. Electric Power Reliability Act of 1967". The legislation did not pass Congress,[1] but the FPC encouraged the formation of a national council on reliability. [5]

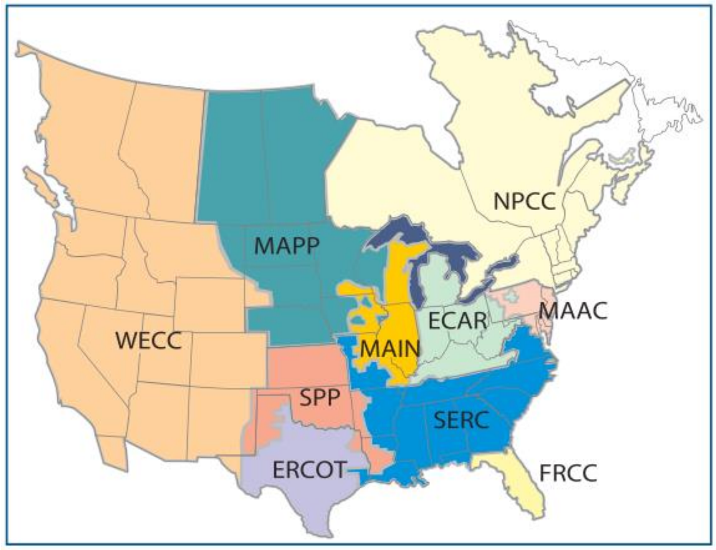


Figure 1 NERC Regions [11]

A coordinating body was formed to provide coordination across North America named the National Electric Reliability Council (NERC). [4] NERC came into being with an agreement dated June 1, 1968, signed by 12 regional and area utility organizations. [5] Regional planning coordination guides were established by NERC. Given the inclusion of Canada in the reliability organization, the name was later changed to North American Electric Reliability Council (NERC). The practices were followed by utilities on a voluntary basis.

1.2 OIL EMBARGO OF 1973 & THE FORMATION OF DOE AND FERC

During the Arab-Israeli war in 1973, United States chose to resupply the Israeli military. As a result, the Organization of Petroleum Exporting Countries (OPEC) led by Saudi Arabia imposed an embargo on the United States and refused to export oil to the United States. At the time the United States was highly dependent upon oil from the middle east and the embargo was a substantial strain on the U.S. economy. [6]

With the realization of the dependence upon energy from foreign sources the United States Congress began to see the need to reduce dependence on foreign energy sources and came to the following conclusions:

> "(1) the United States faces an increasing shortage of nonrenewable energy resources;
>
> (2) this energy shortage and our increasing dependence on foreign energy supplies present a serious threat to the national security of the United States and to the health, safety and welfare of its citizens;
>
> (3) a strong national energy program is needed to meet the present and future energy needs of the Nation consistent with overall national economic, environmental and social goals;
>
> (4) responsibility for energy policy, regulation, and research, development and demonstration is fragmented in many departments and agencies and thus does not allow for the comprehensive,

[1] One has to wonder if industry pressed Congress not to pass the bill in leu of and with the promise of self-regulation, as the reliability councils were formed around the same time.

> centralized focus necessary for effective coordination of energy supply and conservation programs; and
>
> (5) formulation and implementation of a national energy program require the integration of major Federal energy functions into a single department in the executive branch." [7]

Therefore, in 1977 the United States Congress passed the Department of Energy Organization Act. The public law formed the Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC). [7]

DOE has history tracing back to the Manhattan Project and the development of the atomic bomb during World War II and was the combination of federal agencies (including the FPC) and programs related to energy. The various programs were assembled under one department with the Department of Energy Organization Act. The stated mission of the Department of Energy is to ensure America's security and prosperity by addressing its energy, environmental and nuclear challenges through transformative science and technology solutions. [8]

FERC is the federal agency that regulates the interstate transmission of natural gas, oil, and electricity. FERC also regulates natural gas and hydropower projects. FERC's stated mission is: "Economically Efficient, Safe, Reliable, and Secure Energy for Consumers. Assist consumers in obtaining economically efficient, safe, reliable, and secure energy services at a reasonable cost through appropriate regulatory and market means, and collaborative efforts." [9]

In 1980 NAPSIC became part of NERC. The NAPSIC operations criteria and guides were adopted by NERC as part of the junction. In 1992 for the first time the NERC Board stated that conformance to NERC and regional reliability policies, criteria and guides should be mandatory to ensure reliability. However, at that time NERC had no enforcement authority. This meant that the NERC guidelines and standards were still voluntary. [2]

In 1997 the DOE established an Electric System Reliability Task Force, and NERC formed an independent "blue ribbon" panel (the Electric Reliability Panel). Both the DOE Task Force and the NERC panel determined grid reliability rules must be mandatory and enforceable and recommended creating an independent, self-regulatory, electric reliability organization to develop and enforce reliability standards throughout North America. [2]

1.3 NORTHEAST BLACKOUT OF 2003 & THE INCORPORATION OF NERC

On August 14, 2003, the largest blackout in North American history took place. The blackout impacted approximately 50 million people and 61,800 megawatts (MW) of electric load in Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey and Ontario, Canada. [10]

A join U.S.-Canada Power System Outage Task Force was assembled to investigate the blackout. The final report from the task force identifies the causes of the blackout and identifies failures to perform effectively relative to the reliability policies, guidelines, and standards of the North American Electric Reliability Council (NERC) and, in some cases, deficiencies in the standards themselves. [11]

The task force made several recommendations broken into three groups. Group I. Institutional Issues Related to Reliability of the recommendations by the task force included:

> "1. Make reliability standards mandatory and enforceable, with penalties for noncompliance.

2. Develop a regulator-approved funding mechanism for NERC and the regional reliability councils, to ensure their independence from the parties they oversee.

3. Strengthen the institutional framework for reliability management in North America.

4. Clarify that prudent expenditures and investments for bulk system reliability (including investments in new technologies) will be recoverable through transmission rates.

5. Track implementation of recommended actions to improve reliability.

6. FERC should not approve the operation of new RTOs or ISOs until they have met minimum functional requirements.

7. Require any entity operating as part of the bulk power system to be a member of a regional reliability council if it operates within the council's footprint.

8. Shield operators who initiate load shedding pursuant to approved guidelines from liability or retaliation.

9. Integrate a "reliability impact" consideration into the regulatory decision-making process.

10. Establish an independent source of reliability performance information.

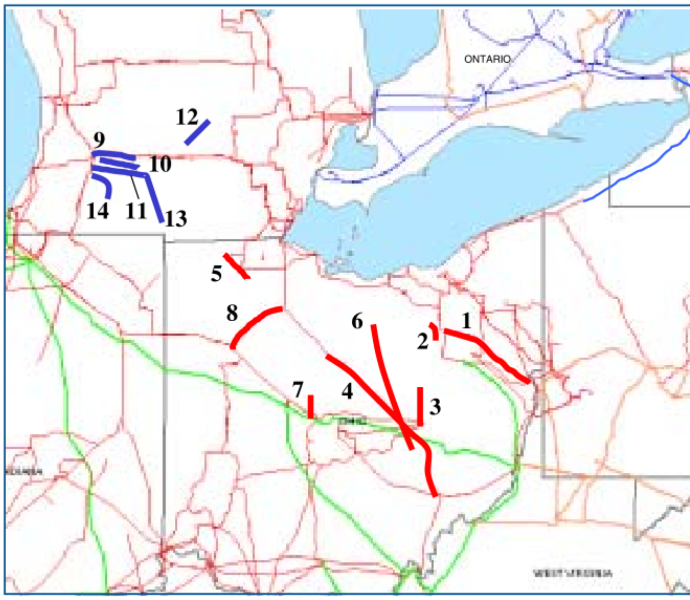
11. Establish requirements for collection and reporting of data needed for post-blackout analyses.

12. Commission an independent study of the relationships among industry restructuring, competition, and reliability.

13. DOE should expand its research programs on reliability-related tools and technologies.

14. Establish a standing framework for the conduct of future blackout and disturbance investigations." [11]

Part of what the Task Force found in their investigation is the need to improve relay protection schemes and coordination, and the need for better application of zone 3 impedance relays on high voltage transmission lines. The illustration below (Figure 2) highlights the impact of zone 3 impedance relays on the spread of the outage. [11] These represent what would often be called relay misoperations.



	Zone 3 Tripped Lines	State	Trip Time (EDT)
1	Sammis - Star (345 kV)	Ohio	16:05:57.504
2	Star (138/69 kV) Transformer # 6 Star - Dale (69kV)	Ohio	16:06:01
3	Ohio CTL - Wooster (138 kV)	Ohio	16:08:58
4	Galion - Ohio CTL - Muskingum (345 kV) @ Muskingum	Ohio	16:08:59.158
5	Richland - Wauseon - Midway (138 kV)	Ohio	16:09:00
6	Academia - Howard (138 kV) Philo - Howard (138 kV)	Ohio	16:09:05
7	Tangy - Kirby (138 kV) Tangy - Crissinger (138 kV)	Ohio	16:09:06
8	E. Lima - Fostoria (345 kV)	Ohio	16:09:06.311
9	Argenta - Battle Ck (345 kV)	Michigan	16:10:36.230
10	Argenta - Tompkins (345 kV) Battle Ck - Oneida	Michigan	16:10:36.310
11	Argenta - Verona (138 kV)	Michigan	16:10:37.550
12	Delhi - Island Road (138 kV)	Michigan	16:10:37.870
13	Verona - Batavia (138 kV)	Michigan	16:10:37.900
14	Argenta - Morrow (138 kV)	Michigan	16:10:38.350

Figure 2 Map of Zone 3 (and Zone 2s Operating Like Zone 3s) Relay Operations on August 14, 2003 [11]

The blackout, task force findings and recommendations lead to the creation of ‘Energy Policy Act of 2003’ which was not passed by Congress but did highlight the need for improvements in the electric power industry. It was another two years before Congress passed a bill to address the issues. In 2005 Congress passed the 'Energy Policy Act of 2005' [12]

The Energy Policy Act of 2005 ordered FERC to setup an Electric Reliability Organization (ERO) with FERC oversite who:

> “(1) has the ability to develop and enforce, subject to subsection (e)(2), reliability standards that provide for an adequate level of reliability of the bulk-power system; and
>
> (2) has established rules that—
>
> > (A) assure its independence of the users and owners and operators of the bulk-power system, while assuring fair stakeholder representation in the selection of its directors and balanced decision making in any ERO committee or subordinate organizational structure;
> >
> > (B) allocate equitably reasonable dues, fees, and other charges among end users for all activities under this section;
> >
> > (C) provide fair and impartial procedures for enforcement of reliability standards through the imposition of penalties;
> >
> > (D) provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and otherwise exercising its duties; “ [12]

In 2006 FERC certified NERC as the “electric reliability organization” for the United States. Shortly thereafter, the North American Electric Reliability Council (NERC) became the North American Electric Reliability Corporation (NERC). In 2007 FERC approved 83 legally enforceable NERC Reliability Standards. Compliance with NERC standards would no longer be voluntary but would be mandatory. [2]

NERC now maintains a set of standards that go through a comment and update procedure as outlined in the Energy Policy Act of 2005. The full set of NERC standards, their history and status are maintained on the NERC website. A convenient place to download a spreadsheet of the standards is located in the 'US Reliability Standards' page of the 'One-Stop-Shop (Status, Purpose, Implementation Plans, FERC Orders, RSAWS)' section of the NERC website at:

https://www.nerc.com/pa/Stand/Pages/USRelStand.aspx

2. PRC-004-6

The NERC standard of interest for this report is: PRC-004-6 — Protection System Misoperation Identification and Correction. The purpose of the standard is to identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES)[2] Elements. [13] This standard applies to:

- Protection Systems for BES Elements (with some exclusions)
- Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.
- Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that misoperates is to have dated evidence that demonstrates that the owner identified the misoperation by the Composite Protection System (CPS)[3] or by manual intervention in response to a Protection System failure. Further the owner is required to provide notification within 120 calendar days of the misoperation. Each Owner that receives notification from another Owner is to identify whether its Protection System component(s) caused a Misoperation within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation. [13]

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[2] Bulk Electric System: unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.
Inclusions:
• I1 - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.
• I2 – Generating resource(s) including the generator terminals through the high-side of the step- up transformer(s) connected at a voltage of 100 kV or above with:
a) Gross individual nameplate rating greater than 20 MVA. Or,
b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.
• I3 - Blackstart Resources identified in the Transmission Operator's restoration plan.
• I4 - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above.
Thus, the facilities designated as BES are:
a) The individual resources, and
b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.
• I5 –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4. [14]

[3] Composite Protection System: the total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded. [14]

Additionally, the owner is to:

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or

- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

Each owner must implement each CAP developed, and have dated evidence of the completion of each CAP. [13]

3. RULES OF PROCEDURE

NERC maintains "Rules of Procedure" (ROP) that are overarching rules that members are required to adhere to. Section 100 "Applicability of Rules of Procedure" states that all NERC members must comply with the ROP, and if a member is unable to comply with the ROP then the member is required to notify NERC as to why they are unable to comply. [14]

Section 1601. "Scope of a NERC or Regional Entity Request for Data or Information" states:

> "Within the United States, NERC and Regional Entities may request data or information that is necessary to meet their obligations under Section 215 of the Federal Power Act, as authorized by Section 39.2(d) of the Commission's regulations, 18 C.F.R. § 39.2(d)." [14]

Section 1600 continues by defining the procedure that NERC is required to follow in requesting data which includes a comment process by participants and an approval by the NERC Board of Trustees. [14]

4. TRANSMISSION OWNER, GENERATOR OWNER, AND DISTRIBUTION PROVIDER REPORTING

A NERC "Request for Data or Information (RDI): Protection System Misoperation Data Collection" was finalized on August 14, 2014, which involved a revision of the Reliability standard PRC-004 which folded PRC-003 into PRC-004 as they were each defined at that time[4]. The Protection System Misoperations Standard Drafting Team (SDT) removed the data reporting obligation included in PRC-004 from the revised standard and recommended that NERC request the data required for performance analysis purposes pursuant to Section 1600 of the NERC Rules of Procedure. [1]

Under the RDI, members are required to report Misoperation data on a quarterly basis. The purpose of this Data Request is to:

> "continue consistent reporting of Misoperation data to NERC through a standardized template for performance analysis" [1]

NERC uses the data to:

- Develop meaningful metrics to assess Protection System performance;

---

[4] PRC-004 is currently on Version 6

- Identify trends in Protection System performance that negatively impact reliability;
- Identify remediation techniques to reduce the rate of occurrence and severity of Misoperations;
- Provide focused assistance to entities in need of guidance; and
- Publicize lessons learned to the industry. [1]

5. BPS MISOPERATIONS IN THE UNITED STATES

Transmission Owners, Generator Owners, and Distribution Providers report Protection System Operations and Misoperations to NERC via the Misoperation Information Data Analysis System (MIDAS) on a quarterly basis, within 60 days of the end of each quarter. MIDAS is the database system maintained by NERC to collect and store the misoperations under NERC jurisdiction.

Figure 3 Reporting Period

Each year NERC uses the MIDAS misoperations data of the Bulk Power System (BPS) provided by electric utilities across the United States. The findings by NERC concerning North American BPS reliability are compiled into an annual report titled “State of Reliability | An Assessment of 2019 Bulk Power System Performance.” Key Finding 6 in the report is concerned with Protection System Misoperations. Chapter 5 goes into greater detail explaining:

> “Leading Causes of Misoperations
>
> The top three causes of misoperations over the past five years are Incorrect Settings/Logic/Design Errors, Relay Failures/Malfunctions, and Communication Failures (See Figure 5.6). For each five-year period analyzed since data collection started, these three causes have consistently accounted for more than 60% of all misoperations.” [15]

The State of Reliability report is reviewed by many industry participants. Rather than being reactive as was the case with the 1965 blackout leading to the formation of NERC. DOE is one of the entities that reviews the State of Reliability report in order to be proactive in addressing issues. The Office of Electricity who is responsible for projects that are addressing advanced protective relaying technologies and tools reviews the report to see were research funding can help to improve matters and prevent future catastrophic events.

The report highlights “Incorrect Settings/Logic/Design Errors” and “Relay Failures/Malfunctions” both relate to relay operations/misoperations. Further, these two categories account for approximately half of the misoperations on the BPS. If approaches can be found to reduce misoperations related to relaying, then the impact could be significant in improving BPS reliability and resiliency.

Finding approaches to reduce misoperations related to relaying starts with understanding the details of what is behind the reported metrics. This project takes a deep dive into the data that feeds Figure 4 to see what can be found regarding trends in the data. The goal of the deep dive into the data is to gain more clarification to the data and an opportunity to see if there are any further/deeper conclusions that could be drawn from the data.

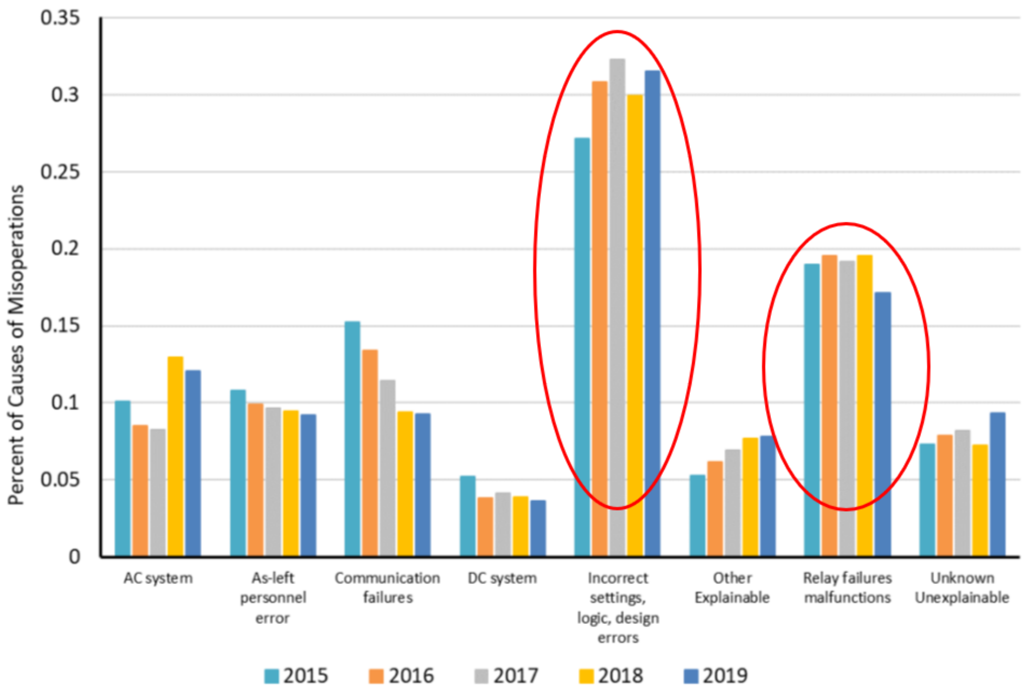

Figure 4 Misoperations by Cause Code (NERC figure 5.6) [15]

5.1 MIDAS DATA ACQUISITION FROM NERC

Staff at Oak Ridge National Laboratory and the U.S. Department of Energy met with Staff from North American Electric Reliability Corporation to discuss the acquisition of MIDAS data for to look further into the data beyond the top cause codes, such as protected equipment type, relay technology etc. The MIDAS data was discussed with NERC to understand the data structure/format/organization, data sources, known issues/limitations in the dataset.

NERC shared the MIDAS data covering misoperations from 2016 through 2020. However, several fields had to be sanitized per:

> "Dissemination of Data: NERC's treatment of confidential information is governed by Section 1500 of NERC's Rules of Procedure and other agreements with Applicable Governmental Authorities. Individual Misoperation reports are considered confidential. Aggregated Misoperation information is considered public information. However, aggregated Misoperation data public reports will not inadvertently release confidential information by the display of regional or NERC information from which an entity's confidential information could be ascertained." [1]

Table 1 Fields within MIDAS

DESCRIPTION
Date that the record was last modified on in UTC.
Datetime. Actual date that the corrective action plan was completed in UTC. Completion of this field is not enforced by the software because if the "Analysis and Corrective Action Status" is "Analysis – In Progress," the entity still has not identified the cause of the issue so the entity is not able to target a CAP date. Creating validation based on the "Analysis and Corrective Action Status", "Corrective Action Plan Target Completion Date", and "Corrective Action Plan Actual Completion Date" would likely exclude some events from being able to be reported.
Datetime. Target date to complete the corrective action plan in UTC. Completion of this field is not enforced by the software because if the "Analysis and Corrective Action Status" is "Analysis – In Progress," the entity still has not identified the cause of the issue so the entity is not able to target a CAP date. Creating validation based on the "Analysis and Corrective Action Status", "Corrective Action Plan Target Completion Date", and "Corrective Action Plan Actual Completion Date" would likely exclude some events from being able to be reported.
Dropdown. The category of the misoperation related to the record.
Dropdown. The cause of the misoperation related to the record.
Description of the corrective action plan that is to be taken. Completion of this field is not enforced by the software because if the "Analysis and Corrective Action Status" is "Analysis – In Progress," the entity still has not identified the cause of the issue or the plan to resolve it so the entity is not able to target a CAP date or describe the plan. Creating validation based on the "Analysis and Corrective Action Status", "Corrective Action Plan Target Completion Date", "Corrective Action Plan", and "Corrective Action Plan Actual Completion Date" would likely exclude some events from being able to be reported.
Dropdown. The most recent status of the corrective action plan.
Datetime. Date that the record was initially reported in UTC.
Field with descriptive name of entity. populated based on submitted NERCID.
Descriptive name of equipment involved in misoperation.
Descriptive name of any equipment removed due to misoperation.
Dropdown. Type of equipment listed in Equipment field.
Description of the misoperation event that occurred.
Descriptive name of the facility at which the misoperation occurred.
Dropdown. Voltage rating of the facility at which the misoperation occurred.
Yes/No Dropdown. Field indicating whether or not the misoperation was also a reportable GADS event.
Field to indicate GADS unit IDs for any units in a forced outage state due to the misoperation.
Dropdown. Field to indicate the reporting company's country jurisdiction.
Datetime. Field to indicate the date and time that the misoperation occurred in UTC.
Seconds portion of the misoperation date.
Unique identifier consisting of concatenation of Region_NERCID_MisoperationDateUTC_Facility_Equipment.
Descriptive field of protection systems and components involved in the misoperation. This field is conditionally required (by both the system and 1600) when the "Cause of Misoperation" is "Relay failures/malfunctions", "Incorrect settings", "Logic errors", or "Design errors".
Dropdown. Field to indicate the region in which the misoperation occurred.
Dropdown. Field to indicate the relay technology involved in the misoperation. This field is conditionally required (by both the system and 1600) when the "Cause of Misoperation" is "Relay failures/malfunctions", "Incorrect settings", "Logic errors", or "Design errors".
Field to indicate element IDs for any TADS elements that experienced a forced outage due to the misoperation.
Yes/No Dropdown. Field indicating whether or not the misoperation was also a reportable TADS outage.
Field to indicate the reporting entity's NCR number.
Field to label each record with CUI-CEII-PRIV status.
Date that the record was last modified on in UTC.
Field with descriptive name of entity. populated based on submitted NERCID.
Dropdown. Field to indicate the reporting company's country jurisdiction.
Concatenated field consisting of entity's NERCID_SubmissionQuarter_SubmissionYear.
Unique identifier consisting of concatenation of SubmissionYear_SubmissionQuarter_NERCID_Region_VoltageClass.
Field to indicate the number of operations that occurred during the indicated quarter.
Dropdown. Field to indicate the region the entity is reporting the operations to.
Dropdown. Quarter that operations in submission occurred.
Dropdown. Year that operations in submission occurred.
Voltage class of the equipment for the reported operations.
Field to indicate the reporting entity's NCR number.
Unique numerical identifier assigned by the system.
Unique numerical identifier assigned by the system.

The MIDAS data provided by NERC is shown in Table 1 and the color code system used to identify the availability of specific fields is shown in Table 2.

Table 2 Availability of Data for Analysis Outside NERC

Available as reported
Available with Alias ID
Confidential - Not Available
Voluntary - Not included

The NERC definition of **Misoperation** has particular value in the context of this report:

> "The failure of a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:
> 1. Failure to Trip – During Fault – A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
> 2. Failure to Trip – Other Than Fault – A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
> 3. Slow Trip – During Fault – A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
> 4. Slow Trip – Other Than Fault – A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
> 5. Unnecessary Trip – During Fault – An unnecessary Composite Protection System operation for a Fault condition on another Element.
> 6. Unnecessary Trip – Other Than Fault – An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation." [16]

In discussions and training with NERC about the MIDAS system it was made clear that in the context of BPS Misoperations to be reported in the MIDAS system, when the same CPS misoperates multiple times in a 24-hour period, the entry into MIDAS is to be entered into MIDAS as one misoperation. This reflects a flawed relay or flawed piece of logic in the CPS rather than each individual outage. It is important to make this distinction when reviewing the MIDAS data.

5.2 ANALYSIS OF THE MIDAS DATASET

The MIDAS dataset provided by NERC covered a five-year period and the entire table fit into a single MS Excel spreadsheet file. The spreadsheet was imported into MS Access in order to organize the data and prepare it for analysis.

Using SQL queries, the data was analyzed to highlight various aspects of the data that were not provided in the State of Reliability report. While many of the same conclusions can be drawn some more specifics within the data were exposed. It is important to note that the percentages listed in the tables to follow represent the percentage against the total reported misoperations in the five-year data set.

Analysis and reporting begin by looking at individual data fields such as category, equipment and relay technology. Table 3 demonstrates that a considerable percentage of the misoperations reported to NERC in the five years window of the data were unnecessary trips, accounting for 95% of the total.

Table 3 Unnecessary Trip Makes Up a Substantial Majority of the Reported Misoperations

PrimaryCategory	Pct
Unnecessary Trip	95.50%
Failure To Trip	3.14%
Slow Trip	1.36%

Table 4 shows that the unnecessary trips are split more or less evenly between occurring during a fault and occurring at times other than a fault.

Table 4 Unnecessary Trips are Shared Somewhat Evenly Between Faults and Other Than Faults

PrimaryCategory - SecondaryCategory	Pct
Unnecessary Trip - During Fault	52.35%
Unnecessary Trip - Other than Fault	43.15%
Failure To Trip - During Fault	2.42%
Slow Trip - During Fault	1.24%
Other (<1% each)	0.84%

Table 5 Illustrates that Line protection packages are by far the most commonly reported misoperations at 58% of all reported misoperations. One possible explanation is that this may be partially due to the number of line protection packages compared to other protection packages (i.e., transformer, generator, etc.).

Table 5 Event Percent by Equipment Type

EquipmentType	Pct
Line	58.20%
Transformer	9.55%
Generator	8.71%
Breaker	8.56%
Bus	6.06%
Shunt Capacitor	5.70%
Other	1.20%
Shunt Reactor/Inductor	1.13%
HVdc	0.34%
Dynamic Var Systems	0.32%
Series Capacitor	0.14%
Series Reactor/Inductor	0.06%
BES UVLS	0.04%

Table 6 Illustrates that Microprocessor relays are by far the most reported misoperations at 58% of all reported misoperations. This may be partially due to the proliferation of microprocessor relays. Over the past three decades, the industry has been shifting away from electromechanical relays and using more microprocessor relays. A significant number of the relays deployed in modern substations are microprocessor based.

Table 6 Microprocessor Relays Account for >58% of All Reported Misoperations

RelayTechnology	Pct
Microprocessor	58.53%
Electromechanical	17.66%
NULL	11.80%
N/A	6.26%
Solid State	4.89%
Other	0.87%

Table 7 exposes that incorrect settings account for approximately a quarter of all reported misoperations, these events are likely tied back to the protection engineers that designed the settings and the technicians that programmed the settings into the relays. Part of this is likely due to the increased complexity and programmability of today's modern microprocessor relays.

Approximately one fifth of the reported misoperations are tied to relay failures/malfunctions. These events are presumably tied back to the relay itself and potentially manufacturer defects or damage due to things like lightning strikes.

Another one tenth of the misoperations are tied to communication failures. Communication systems have become increasingly complicated in modern substations and power systems.

Table 7 Incorrect Settings are the Leading Cause of Reported Misoperations

Cause	Pct
Incorrect settings	23.45%
Relay failures/malfunctions	18.87%
Communication failures	10.64%
AC system	10.17%
As-left personnel error	10.06%
Unknown/unexplainable	7.53%
Other/Explainable	7.16%
Design errors	4.83%
DC system	3.99%
Logic errors	2.84%
Incorrect settings/logic/design errors	0.45%

The analysis continues by investigating combinations of two data fields such as equipment with relay technology. Table 8 exemplifies how approximately one third of the reported misoperations are associated with microprocessor relays of line protection packages. An additional 10% of reported misoperations are associated with electromechanical relays that are part of line protection packages. This follows along with the findings from the 2003 blackout where one of the contributing factors to the spread of the blackout was due to zone three settings for line protection packages.

Table 8 Line Protection Events Account for >58% of Reported Misoperations

Equipment - RelayTechnology	Pct
Line - Microprocessor	34.60%
Line - Electromechanical	10.45%
Line - NULL	6.84%
Transformer - Microprocessor	5.56%
Breaker - Microprocessor	5.08%
Generator - Microprocessor	4.69%
Shunt Capacitor - Microprocessor	3.69%
Line - N/A	3.52%
Bus - Microprocessor	3.01%
Line - Solid State	2.55%
Generator - Electromechanical	1.89%
Transformer - Electromechanical	1.87%
Bus - Electromechanical	1.47%
Breaker - Electromechanical	1.40%
Breaker - NULL	1.00%
Other (<1% each)	12.37%

Table 9 discloses that incorrect settings, relay failures and communication failures are the leading factors in unnecessary trips.

Table 9 Incorrect Settings Contribute Significantly to Unnecessary Trips

PrimaryCategory - Cause	Pct
Unnecessary Trip - Incorrect settings	22.49%
Unnecessary Trip - Relay failures/malfunctions	17.91%
Unnecessary Trip - Communication failures	10.45%
Unnecessary Trip - AC system	9.83%
Unnecessary Trip - As-left personnel error	9.62%
Unnecessary Trip - Unknown/unexplainable	7.19%
Unnecessary Trip - Other/Explainable	6.77%
Unnecessary Trip - Design errors	4.54%
Unnecessary Trip - DC system	3.50%
Unnecessary Trip - Logic errors	2.75%
Other (<1% each)	4.97%

Table 10 relates relay technology to cause where microprocessor-based relays with incorrect settings account for twice the percentage of the next leading category of microprocessor relay malfunctions. The third leading category in the table is that of electromechanical relay failures and is approximately one third the percentage of the leading category.

Table 10 Relay Technology & Cause Where Most of the Top Groups are Microprocessor Relays

RelayTechnology - Cause	Pct
Microprocessor - Incorrect settings	21.42%
Microprocessor - Relay failures/malfunctions	9.75%
Electromechanical - Relay failures/malfunctions	6.58%
Microprocessor - As-left personnel error	5.15%
Microprocessor - AC system	4.72%
Microprocessor - Communication failures	3.63%
Microprocessor - Other/Explainable	3.44%
Microprocessor - Design errors	3.29%
NULL - Communication failures	2.79%
Microprocessor - Logic errors	2.73%
Microprocessor - Unknown/unexplainable	2.57%
NULL - AC system	2.53%
Electromechanical - Unknown/unexplainable	2.44%
NULL - As-left personnel error	2.22%
Electromechanical - Communication failures	2.16%
Solid State - Relay failures/malfunctions	2.13%
NULL - Unknown/unexplainable	1.57%
NULL - Other/Explainable	1.45%
Microprocessor - DC system	1.43%
Electromechanical - AC system	1.35%
N/A - Communication failures	1.28%
N/A - AC system	1.27%
Electromechanical - As-left personnel error	1.24%
Electromechanical - Incorrect settings	1.21%
Electromechanical - Other/Explainable	1.18%
N/A - As-left personnel error	1.18%
NULL - DC system	1.16%
Other (<1% each)	8.14%

Table 11 reveals that the leading causes are all tied to line protection packages with the top of the list being incorrect settings followed by relay failures functions closely followed by communication failures which is consistent with what might be expected given the information in Table 5 and Table 7.

Table 11 Equipment Type & Cause Where All the Top Groups are Line Protection

EquipmentType - Cause	Pct
Line - Incorrect settings	15.49%
Line - Relay failures/malfunctions	10.92%
Line - Communication failures	10.05%
Line - As-left personnel error	4.75%
Line - Unknown/unexplainable	4.09%
Line - Other/Explainable	3.65%
Line - AC system	3.37%
Transformer - Incorrect settings	2.44%
Line - Design errors	2.35%
Breaker - Relay failures/malfunctions	2.19%
Shunt Capacitor - AC system	2.06%
Transformer - As-left personnel error	1.84%
Line - Logic errors	1.78%
Generator - Relay failures/malfunctions	1.73%
Generator - AC system	1.69%
Generator - Incorrect settings	1.65%
Line - DC system	1.47%
Transformer - Relay failures/malfunctions	1.47%
Bus - Relay failures/malfunctions	1.45%
Shunt Capacitor - Incorrect settings	1.34%
Breaker - Incorrect settings	1.21%
Transformer - AC system	1.06%
Breaker - DC system	1.02%
Breaker - As-left personnel error	1.02%
Other (<1% each)	19.92%

5.2.1 A Closer Look at Line Protection

Given that line protection packages account for such a large percentage of the overall reported misoperations, this subsection takes a closer look at line protection packages within the data set. The percentages listed in these tables are also calculated against the total number of ported misoperations. Therefore, the percentages in these tables will not sum to 100%.

Table 12 Microprocessor Relays are the Dominant Source of Unnecessary Trips on Lines

Line Protection Detail-1	Pct
Microprocessor - Unnecessary Trip	33.35%
Electromechanical - Unnecessary Trip	9.44%
NULL - Unnecessary Trip	6.61%
N/A - Unnecessary Trip	3.34%
Solid State - Unnecessary Trip	2.46%
Other (<1% each)	3.01%

Table 12 specifically goes into detail of line protection packages narrowing down the relay technology and primary category. The table unveils how one third of all reported unnecessary trips are associated with line protection packages with microprocessor relays. Table 13 reinforces what was learned from Table 7, but narrows the focus to line protection packages showing how incorrect settings leads the list followed by relay failures and then by communication failures.

Table 13 Incorrect Settings are the Leading Cause of Misoperations on Lines

Line Protection Detail-3	Pct
Incorrect settings	15%
Relay failures/malfunctions	11%
Communication failures	10%
As-left personnel error	5%
Unknown/unexplainable	4%
Other/Explainable	4%
AC system	3%
Design errors	2%
Logic errors	2%
DC system	1%
Incorrect settings/logic/design errors	0%
Not Line	42%

Table 14 follows with Table 9 but focuses on unnecessary trips by line protection packages but presents a very similar prioritized list led by incorrect settings then relay failures and communication failures.

Table 14 Incorrect Settings are the Leading Cause of Unnecessary Trips on Lines

Line Microprocessor Detail	Pct
Unnecessary Trip - Incorrect settings	13.89%
Unnecessary Trip - Relay failures/malfunctions	5.59%
Unnecessary Trip - Communication failures	3.33%
Unnecessary Trip - As-left personnel error	2.15%
Unnecessary Trip - Other/Explainable	1.84%
Unnecessary Trip - Logic errors	1.69%
Unnecessary Trip - Design errors	1.51%
Unnecessary Trip - AC system	1.46%
Unnecessary Trip - Unknown/unexplainable	1.23%
Other (<1% each)	0.66%

Based on the findings of single and dual data fields, multiple combinations of data fields are used to investigate deeper into the data of line misoperations. Table 15 brings together the primary category, the relay technology, and the causes for line protection package misoperations. The top of the list represented by microprocessor relays with incorrect settings followed by microprocessor relay failures. Third in the list is electromechanical relay failures closely followed by microprocessor communication failures.

Table 15 Incorrect Settings are the Leading Cause of Unnecessary Trips with Microprocessor Relays on Lines

Line Protection Detail-2	Pct
Unnecessary Trip - Microprocessor - Incorrect settings	13.89%
Unnecessary Trip - Microprocessor - Relay failures/malfunctions	5.59%
Unnecessary Trip - Electromechanical - Relay failures/malfunctions	3.72%
Unnecessary Trip - Microprocessor - Communication failures	3.33%
Unnecessary Trip - NULL - Communication failures	2.62%
Unnecessary Trip - Microprocessor - As-left personnel error	2.15%
Unnecessary Trip - Electromechanical - Communication failures	2.01%
Unnecessary Trip - Microprocessor - Other/Explainable	1.84%
Unnecessary Trip - Microprocessor - Logic errors	1.69%
Unnecessary Trip - Microprocessor - Design errors	1.51%
Unnecessary Trip - Microprocessor - AC system	1.46%
Unnecessary Trip - Electromechanical - Unknown/unexplainable	1.32%
Unnecessary Trip - Microprocessor - Unknown/unexplainable	1.23%
Unnecessary Trip - N/A - Communication failures	1.23%
Unnecessary Trip - NULL - As-left personnel error	1.17%
Other (<1% each)	13.39%

6. CONCLUSIONS

It is clear from the data that unnecessary trips are by far the leading category of reported misoperations. The data also makes clear that a majority of misoperations are those of line protection packages. Further, most misoperations are tied to microprocessor relays. Nearly one quarter of reported misoperations are due to incorrect settings and another one quarter of reported misoperations are due to relay failures/malfunctions and communication failures. Given that line protection packages and microprocessor relays are so involved in misoperations, these would be areas of prime opportunity for further investigation and research & development.

7. PROJECT RELEVANCE

Issues that lead to major events are often known by specialists within the field well before a catastrophic event takes place. However, all too often the specialists within a field are unsuccessful in raising awareness or concern to a level at which measures can be taken to prevent a major event. The northeast blackout of 1965 is an illustration of how a major event is required to raise awareness to a level to instigate change. These major events could be called “catalyzing events” as they are the events that act as the catalyst to change and without the event the change postponed indefinitely. The catalyzing event that led to the formation of NERC is the 1965 blackout. The catalyzing event that led to the formation of the DOE and FERC is the OPEC oil embargo and the catalyzing event that led to the voluntary NERC guidelines becoming mandatory standards was the 2003 blackout.

A specialist in the field has highlighted the significance of misoperations in “NERC President’s Top Priority Issues for Bulk Power System Reliability – January 7, 2011” the top listed item is Misoperations of relay protection and control systems stating:

> “Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. Protection systems are designed to operate reliably when needed under the presence of a fault on the system, to quickly isolate a piece of equipment or a ‘zone’ of the bulk power system, without allowing the fault to transfer into adjoining facilities. The greater the number of facilities involved in an event, the more severe the impact to the rest of the bulk power system, with cascading failure such as resulted from the “Zone 3 Relay” issue in the August 2003 blackout being the extreme. Relays can misoperate, either operate when not needed or fail to operate when needed, for several reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization. Adding to the risk is that system protection is an extremely complex engineering field –there are many practitioners but few masters.” [17]

This investigation was commissioned by the Office of Electricity of the Department of Energy in response to reviewing the NERC State of Reliability report. The study is an attempt to proactively address electric utility industry needs before the catalyzing event takes place.

The investigation of misoperations on the North American BPS has yielded more insight into BPS misoperations related to relaying and controls. It has identified potential areas to focus on in directing research and development opportunities to minimize misoperations associated with relaying and control systems. The investigation has identified opportunities to investigate techniques and tools assist engineers in preventing misoperations in the future.

7.1 OPPORTUNITIES AND RECOMMENDATIONS

Based on the analysis of the data it is pretty clear that the leading causes of misoperations are related to line protection packages with microprocessor relays. What the data does not support our specifics about the relays such as make or model or firmware version etc. Further, with respect to incorrect settings it is impossible clearly tie the incorrect settings cause to any particular relaying philosophy or experience level of the protection engineer or technician working on misoperation of relays etc.

This study has helped to narrow down the leading causes of misoperations but would best be supplemented by a more detailed look at event records. Specifically, notes fields which were excluded from the data set could help to provide more insight into misoperations. While NERC is not at liberty to share certain information, it may be worthwhile to go directly to some of the reporting utilities to request specifics about misoperations particularly misoperations of line protection packages. If the notes and/or investigation reports prove inconclusive in the next step would be to work directly with one or more willing utilities to investigate a wide range of reported misoperations.

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