N-1-1 AC Contingency Analysis as a Part of NERC Compliance Studies at Midwest ISO

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***Abstract*— This paper addresses the development, testing and implementation of a fast automated process for assessing power system performance following loss of two bulk transmission elements consecutively (N-1-1 contingency analysis) and simultaneously (N-2 contingency analysis). The approach described in this paper offers a flexibility to utilize various sets of system adjustments depending on types and values of post-contingency limit violations. It also incorporates sequential contingency simulation in order to identify potential cascading modes due to thermal overloads. Massive AC contingency analysis, automatically identifying various sets of system adjustments and prediction of cascades are performed within one computational run. The proposed process is utilized as a part of Midwest ISO's NERC-compliance studies. Flexible reporting ensures that the obtained results are seamlessly integrated into the Midwest ISO's existing reliability results database. This approach may be used by ISOs and utilities as a part of their compliance studies to assess and improve the reliability of a transmission grid and reduce its vulnerability to cascading outages.**

***Index Terms*— Cascading Outages, N-1-1 and N-2 AC Contingency Analysis, NERC Compliance Studies, Power System Reliability, Transmission Planning Standards.**

I. INTRODUCTION

THE purpose of North American Electric Reliability Corporation's (NERC's) compliance program is improving the reliability of the bulk transmission system in North America "by fairly and consistently enforcing compliance with NERC standards", [1]. All bulk power system owners, operators, and users must comply with approved NERC reliability standards.

NERC-compliance studies address the issue of assessing power system performance following normal and contingency conditions. These studies ensure that the transmission system performance meets NERC Reliability Standards, [2], and that the upgrades to meet future system needs are developed such that reliable and secure operation of the system is maintained.

Transmission Planning (TPL) standards define reliable system performance following a loss of single bulk electric element, two or more bulk electric elements, or following extreme events. NERC, under its transmission planning standards [3], requires analysis of the following categories of contingencies:

- Resulting in a loss of a single element (Category B);
- Resulting in a loss of two or more (multiple) elements (Category C);
- Extreme events resulting in two or more elements removed or cascading out of service (Category D).

A new NERC TPL standard TPL-001-1 (Transmission System Planning Performance Requirements) that is scheduled to be submitted to the regulatory authorities for approval in 1Q2010 requires a more systematic and diligent contingency analysis, including exhaustive N-2 contingency analysis (loss of two elements simultaneously), N-1-1 contingency analysis (loss of two elements consecutively), and assessment of cascading outages.

The need to provide the system planner with fast and automated process to effectively perform NERC-compliance studies is vital and growing more acute. In addition, this process should be used to assist planners in optimizing transmission system expansion which will reduce blackout risk and improve transmission system reliability, [4 - 6].

The paper addresses the development, testing and implementation of a fast automated process to facilitate Midwest ISO planning practices such that NERC TPL standards are met. This framework for N-1-1 and N-2 contingency analysis has the capability to perform the following computations within one simulation run:

- Identify critical contingencies;
- Determine transmission system bottlenecks;
- Determine potential cascading chains;
- Compute minimum amount of necessary system adjustments ;
- If load shed is required, minimize the amount of load curtailment in order to maintain reliable operation of the power system;
- Automatic reporting capabilities.

Preliminary results showed that the technique utilized in the study is a very fast and effective approach to performing NERC-compliance studies.

The programs "Physical and Operational Margins" (POM) and "OPtimal Mitigation Measures" (OPM) of POM Suite were used as the basis for all computations in this study, [7-9].

II. MIDWEST ISO PLANNING PRACTICES

Category C3 events are defined in the North American Electric Reliability Corporation (NERC) Transmission Planning (TPL) standard TPL-003 as Single Line to Ground (SLG) or Three Phase (3Ø) Fault (on a generator, transmission circuit, or transformer) with Normal Clearing, Manual System Adjustments, followed by another SLG or 3Ø Fault, with

Normal Clearing.

Table I of this standard describes the permissible system performance for these C3 events as requiring:

- System should be stable;
- Thermal and Voltage Limits are within Applicable Rating;
- No Cascading Outages;
- Planned / Controlled Loss of Demand or Curtailed Firm Transfers is permitted.

This performance requirement is footnoted as saying that "Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems."

The combined result of these requirements under the tariff, and under the NERC TPL standards, is that for Category C3 events such as the sequential (non-simultaneous) loss of a generator and a line or transformer or generator, the loss of 2 lines or 2 transformers, or of a line and a transformer, compliance with the standard permits the controlled tripping of generators, redispatch of resources resulting in the curtailment of firm transfers, or load shed, if required in order to prevent instability or cascading outages and maintain all thermal loadings and substation voltages within applicable rating.

Midwest ISO tariff defines Baseline Reliability Projects as Network Upgrades identified in the base case as required to ensure that the Transmission System is in compliance with applicable national Electric Reliability Organization (ERO) reliability standards and reliability standards adopted by Regional Reliability Organizations and applicable within the Transmission Provider Region. Furthermore, the tariff also requires the planning process develop the most efficient and cost-effective transmission that will meet reliability needs. Therefore, to the extent redispatch or load shed intended to address potential constraints resulting from NERC-C3 contingent events are deemed more cost effective and feasible options to maintain system reliability than transmission expansions, such projects will not be accepted as Baseline Reliability Projects eligible for cost sharing (subject to passing project cost thresholds of Midwest ISO tariff).

III. MIDWEST ISO METHODOLOGY

A. System Adjustments not involving Generation Redispatch and Load Shed

System adjustments such as noted below are generally considered least cost feasible options to mitigate constraints and thus are tested prior to generation redispatch or load shed.

- Changing voltage schedules at generator terminal stations to alter reactive output of generators within their specified machine capabilities;
- Changing Phase Angle Regulator settings within their specified equipment capabilities;
- Changing Static Var Device control settings;
- Changing Under Load Tap Changer control settings.

B. Redispatch

Redispatch will generally be considered as an acceptable system adjustment to be made following loss of the first element of a Category C3 Event, and prior to the loss of the second element. It is assumed, unless demonstrated to the contrary, that the expected value of cost of such a redispatch following the actual loss of the first element would be very low and would always be an economically superior solution to any Network Upgrade. This is because of the very low probabilities of being in the post single contingency outage state coupled with the system load and dispatch conditions resulting in reliability violations. Due to further lower probabilities associated with the occurrence of the second event following the outage of the first element, redispatch of generation to meet system performance requirements of NERC TPL003 Table 1, will always be considered more cost effective than a transmission network upgrade. To the extent that such redispatch of Midwest ISO generation is shown to be available using the applicable Midwest ISO MTEP planning model, the Midwest ISO business practice will be to consider this as an acceptable solution to address constraints driven by the C3 event.

C. Load Shed

Because the NERC TPL standards do not state a limit as to the amount of load shedding that is permissible in order to maintain system stability, to avoid cascading outages and to maintain all thermal loadings and substation voltages within applicable rating following a Category C3 event, the Midwest ISO practice is to accept as a Baseline Reliability Project eligible for cost sharing (subject to passing the project cost thresholds of Midwest ISO tariff), a Network Upgrade that is needed to avoid any of the following, after the redispatch options have been exhausted:

1. Instability or an unbounded cascade following the second element outage, controlled Load shedding of 100 MW or more implemented as an operating guide prior to the second element outage.
2. Bounded thermal cascading outages resulting in 300 MW or more of load as a consequence of sequential element trips, demonstrated using thermal cascading outage testing method or planned to maintain all thermal loadings and substation voltages within applicable rating.
3. Loss of electric service to more than 50,000 customers as estimated by the Transmission Owner with agreement from the affected Local Distribution Company, and as a consequence of sequential element trips, demonstrated using thermal cascading outage testing method or planned to maintain all thermal loadings and substation voltages within applicable rating.

Condition 1, above has a lower load loss amount than condition 2, because condition 1 would shed this load after a single contingency in anticipation that the second contingency would result in an unbounded cascading event. Condition 2 would result in the larger amount of lost load only in the event that the second contingency actually occurred, and therefore would occur with much less frequency. Condition 3 reflects that in lower average customer peak demand areas, 50,000 customers may represent less than 300 MW of load, but would represent a similarly severe customer outage event.

The above conditions are based on the threshold reporting requirements established for emergency events by the Department of Energy (DOE) and reportable on form OE-417. See http://www.oe.netl.doe.gov/oe417.aspx. The Electric Emergency Incident and Disturbance Report provides information on electric emergency incidents and disturbances. The Department of Energy uses the information to fulfill its overall national security and other energy emergency management responsibilities, as well as for analytical purposes. DOE will use the data from this form to obtain current information regarding emergency situations on U.S. electric energy supply systems. DOE's Energy Information Administration (EIA) will use the data for reporting on electric power emergency incidents and disturbances in monthly EIA reports. The data also may be used to develop legislative recommendations, reports to the Congress and as a basis for DOE investigations following severe, prolonged, or repeated electric power reliability problems.

D. Thermal Cascade Outage Testing Method

Thermal overloads greater than 125% of emergency rating will be flagged and reviewed as follows:

- Contingency events that would result in post-contingent line loading of 125% of the monitored element's emergency limit are flagged.
- The contingency causing the overload and the line overloaded >125% are both removed from service and model resolved.
- Selected lines with loading over 100% of emergency rating are also opened and case resolved until no lines exceed emergency rating or solution diverges.
- If case solves, then amount of load shed as result of line trips is determined.

IV. IMPLEMENTATION STRATEGY

A. Developed Logic for N-1-1 Massive AC Contingency Analysis

The strategy to perform massive N-1-1 AC contingency focused on providing Midwest ISO planning engineers with a solution that has the following capabilities:

- Automatically creates (N-1-1) contingency lists;
- Automates the process of N-1-1 contingency analysis;
- Allows the user to implement various sets of system adjustments within one run;
- Incorporates analysis of cascading outages;
- Provides reporting consistent with past Midwest ISO practice.

At first, the pairs of (N-1-1) contingencies are automatically generated. The first (N-1) contingency is selected from one of the control areas or a set of control areas, while the second (N-1) contingency is selected from another area or set of areas. Note that the change in the order of applying the first and the second (N-1) contingency may yield a different result during (N-1-1) contingency analysis.

Bulk transmission elements 200 kV and above and generating units 200 MW and above are automatically selected as (N-1) contingencies and combined into pairs.

Two different approaches are used for assessment of the first and the second (N-1) contingency in each (N-1-1) contingency pair, and different system adjustments are automatically invoked for the first and the second (N-1) contingency during the study.

The approach, with some modifications, is applicable to N-1 and N-2 contingency analysis.

The contingency analysis algorithm is not specific to any particular base case. In Midwest ISO, various base powerflow cases are developed to represent a variety of system conditions such as Peak, Off Peak, Light Load scenarios. This algorithm has been at this time tested in Midwest ISO's Peak case. Future Studies will include analysis using this algorithm in the Shoulder Peak and Light Load Cases to determine and document precise amount of available generation redispatch among other mitigations to alleviate potential transmission constraints.

B. Analysis of the First (N-1) Contingency in an (N-1-1) Contingency Pair

The analysis of the first (N-1) Contingency in an (N-1-1) contingency pair depends on post-contingency violations. Three scenarios for the mitigation process are:

1. A contingency does not cause violations, (see Fig. 1).
   Proceed to the second contingency in the (N-1-1) contingency pair.
   System adjustments are not needed.

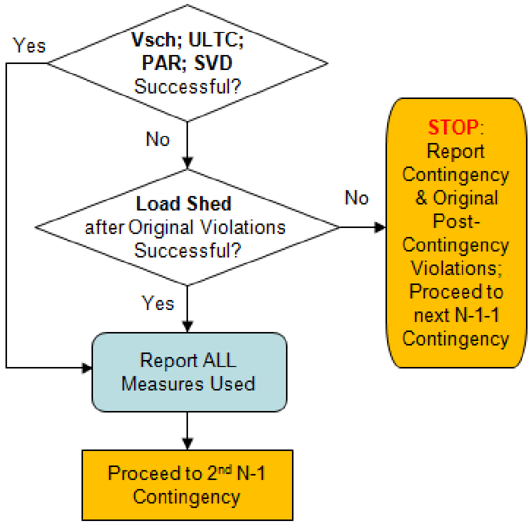


Fig. 1. Mitigation Process after the First (N-1) Contingency: System Adjustments after Steady-State Stability Violation

2. A contingency results in steady-state stability violation (see Fig. 1).
   Perform the following system adjustments:

2.1 MVAr redispatch (Vsch); transformer tap change (ULTC); phase-shifter adjustment (PAR); switching capacitors/reactors (SVD).

Adjustments (2.1) are performed in the order listed above.

2.2 If violations remain after adjustments (2.1), do load shed after the original post-contingency violations (e.g., prior to applying adjustments listed in item (2.1))

2.3 If system adjustments (2.1) – (2.2) are successful, then:

2.3.1 Report all systems adjustments (e.g., mitigation measures)

2.3.2 Proceed to the second contingency in the (N-1-1) contingency pair.

2.4 If system adjustments (2.1) – (2.2) are not successful:

2.4.1 Proceed to the next (N-1-1) contingency pair.

3. A contingency results in voltage and/or thermal violations. Perform the following system adjustments (see Fig. 2):

3.1 MVAr redispatch (Vsch); transformer tap change (ULTC); phase-shifter adjustment (PAR); switching capacitors/reactors (SVD).

Adjustments (3.1) are performed in the order listed above.

3.2 If violations remain after adjustments (3.1), do real power redispatch (MW redispatch).

3.3 If violations remain after adjustments (3.2), do load shed after the original post-contingency violations (e.g., prior to applying adjustments listed in items (3.1) and (3.2) above.)

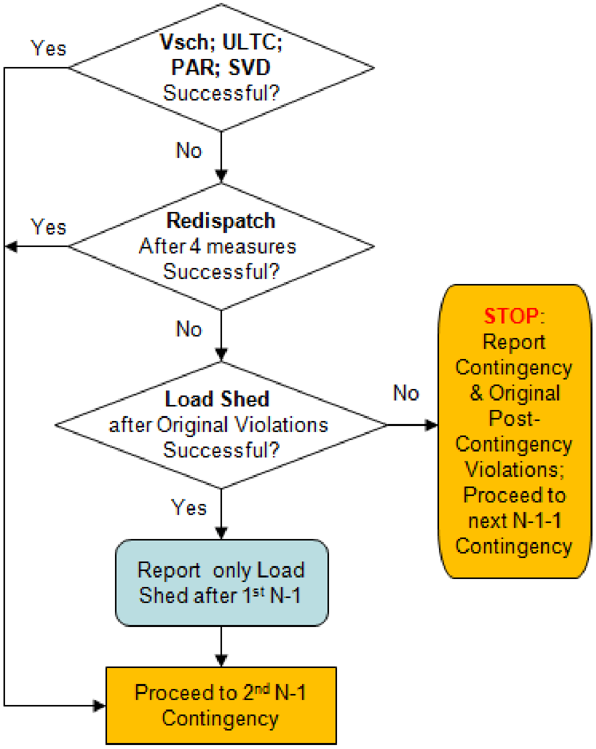


Fig. 2. Mitigation Process after the First (N-1) Contingency: System Adjustments after Voltage/Thermal Violations

3.4 If system adjustments (3.1) – (3.3) are successful (see Fig. 2), then:

3.4.1 Report load shed

3.4.2 Proceed to the second contingency in the (N-1-1) contingency pair.

3.5 If system adjustments (3.1) – (3.3) are not successful, then:

3.5.1 Report original post-contingency violations (e.g., prior to making any system adjustments).

3.5.2 Proceed to the next (N-1-1) contingency pair.

C. Analysis of the Second (N-1) Contingency in an (N-1-1) Contingency Pair

The analysis of the second (N-1) Contingency in an (N-1-1) contingency pair also depends on post-contingency violations. Three scenarios for mitigation process are:

1. A contingency does not cause violations, (see Fig. 3). Proceed to the next (N-1-1) contingency pair. System adjustments are not needed.

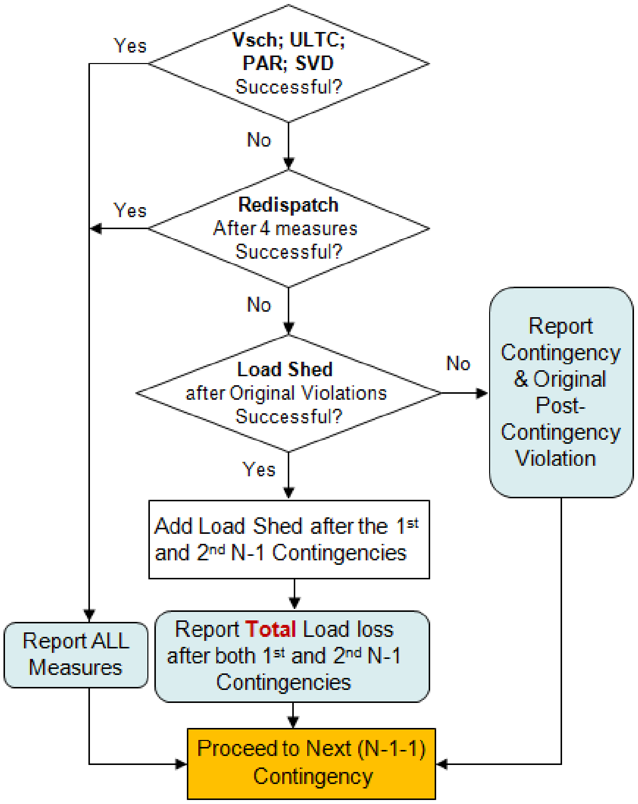


Fig. 3. Mitigation Process after the Second (N-1) Contingency: System Adjustments after Steady-State Stability Violation

2. A contingency results in steady-state stability violation. Perform the following system adjustments, (see Fig. 3):

2.1 MVAr redispatch (Vsch); transformer tap change (ULTC); phase-shifter adjustment (PAR); switching capacitors/reactors (SVD).

Adjustments are performed in the order listed above.

2.2 If violations remain after adjustments (2.1), do real power redispatch (MW redispatch).

2.3 If violations remain after adjustments (2.2), do load shed after the original post-contingency violations (e.g., prior to applying adjustments listed in items (2.1) and (2.2) above.)

If system adjustments (2.1) – (2.2) are successful:
  - 2.3.1 Report all systems adjustments (e.g., mitigation measures)
  - 2.3.2 Proceed to the next (N-1-1) contingency pair.
- 2.4 If system adjustments (2.3) are successful, then:
  - 2.4.1 Compute the sum of load shed after the first and the second (N-1) contingency in the pair.
  - 2.4.2 Proceed to the next (N-1-1) contingency pair.
- 2.5 If adjustments (2.1) – (2.3) are not successful, then proceed to the next (N-1-1) contingency pair.

3. A contingency results in voltage and/or thermal violations. Perform the following system adjustments, (see Fig. 4):
   - 3.1 MVAr redispatch (Vsch); transformer tap change (ULTC); phase-shifter adjustment (PAR); switching capacitors/reactors (SVD).
     Adjustments (3.1) are performed in the order listed above.

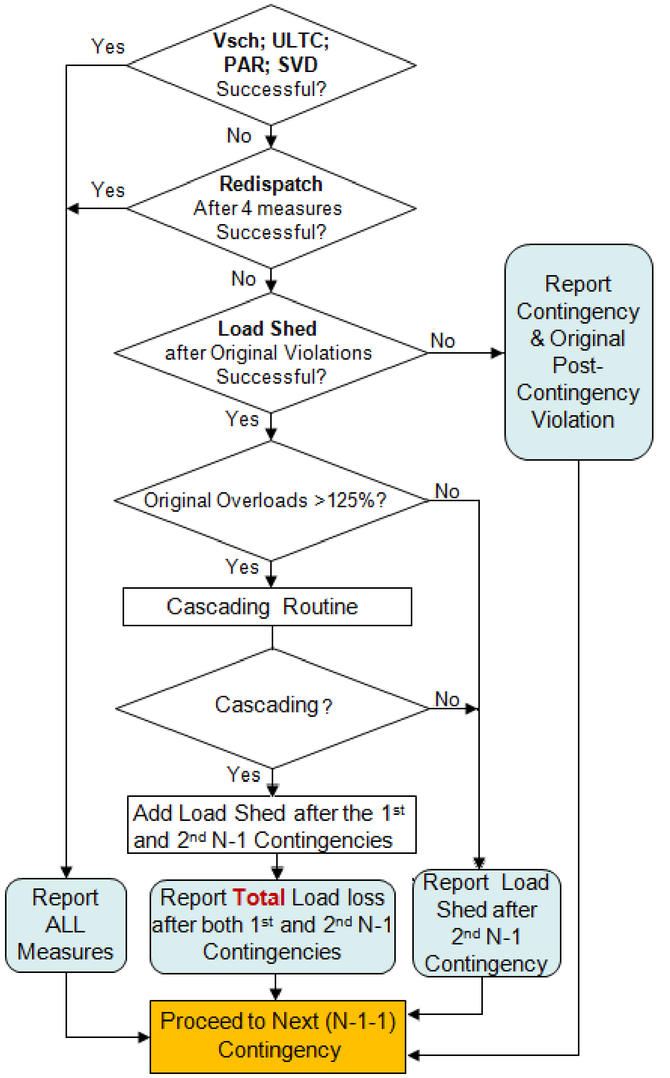


Fig. 4. Mitigation Process after the Second (N-1) Contingency: System Adjustments after Voltage/Thermal Violations

   - 3.2 If violations remain after adjustments (3.1), do real power redispatch (MW redispatch).
   - 3.3 If violations remain after adjustments (3.2), do load shed after the original post-contingency violations (e.g., prior to applying adjustments listed in items (3.1) and (3.2) above.)
   - 3.4 If original overload (e.g., prior to system adjustments) is less than 125% of monitored Rate:
     - 3.4.1 Report load shed
     - 3.4.2 Proceed to the next (N-1-1) contingency pair.
   - 3.5 If original overload (e.g., prior to system adjustments) exceeds 125% of monitored Rate:
     - 3.5.1 Perform Cascading Routine.
     - 3.5.2 If cascading exists, compute and report the sum of load shed after the first and the second (N-1) contingency in the pair.
     - 3.5.3 If cascading does not exist, report load shed after the second (N-1) contingency in the pair.
     - 3.5.4 Proceed to the next (N-1-1) contingency pair.
   - 3.6 If system adjustments (3.1)– (3.3) are not successful:
     - 3.6.1 Report original post-contingency violations (e.g., prior to making any system adjustments).
     - 3.6.2 Proceed to the next (N-1-1) contingency pair.

D. Cascading Routine

The Cascading Routine is automatically initiated after the second (N-1) contingency in a contingency pair if the following conditions are met:

- System adjustments (MVAr redispatch; transformer tap change; phase-shifter adjustment; switching capacitors/reactors, and redispatch) do not completely alleviate post-contingency voltage and/or thermal violations;
- Post-contingency overload(s) exceeds the user-specify threshold.
  For the present study, the threshold is set to 125% of Rate B.

The Cascading Routine automatically trips a branch (or branches) overloaded above the threshold, and then, consecutively, all branches that are overloaded above 100% of Rate B. Cascading analysis proceeds until one of the following events occurs:

- Three or less branches are opened and there are no more overloads above 100% of Rate B.
  This means that there is **bounded cascade** (see "Cascading" block in Fig. 4).
- Three branches are opened, but overloads above 100% of Rate B exist.
  This means that there is **unbounded cascade** (see "Cascading" block in Fig. 4).
- Three or less branches are opened and there is a steady-state stability violation.
  This means that there is **unbounded cascade** (see "Cascading" block in Fig. 4).

If there is no cascading, then load shed is computed and reported only after the second (N-1) contingency in the (N-1-1) contingency pair.

If there is cascading, then the total amount of load shed after the first and the second (N-1) contingency in the (N-1-1) contingency pair is reported.

In prior planning analyses for Category C outages, if thermal overloads exceeded 125%, that branch was tripped as a proxy for zone 3 relay setting. Subsequent to a powerflow solution additional overloaded branches were tripped. However, the extent to which one would continue tripping branches before declaring an unbounded cascade issue, varied across different systems. The intent behind limiting branch trips to 3 (total 5 outages including the Category C contingent event) across the Midwest ISO system was to arrive at a least common denominator to define an unbounded cascade situation that would require a pre-contingent load shed of the amount documented by the program. Actual loads that would be included in operating guides may or may not directly correlate with loads identified in planning simulations.

V. STUDY RESULTS FOR N-1-1 CONTINGENCY ANALYSIS

The present study is the first automated massive N-1-1 AC contingency analysis study performed by Midwest ISO.

The benefits of the proposed framework are:

- Fully automated – all computations described in Section IV are performed within one computational run.
- Very fast – takes appox. 7 sec to analyze one (N-1-1) contingency for a 58,000-bus Midwest ISO planning load flow case on an Intel® Core2 Quad @ 2.0 Ghz processor.

  Analysis of one contingency includes: applying both (N-1) contingencies in the pair; implementing various sets of system adjustments, performing analysis of cascading outages, and reporting the results.
- Flexible reporting.

During the first run that has been made, single elements (see Section IV.A) from a Midwest ISO control area (including tie-lines) were considered as the first (N-1) contingency in the contingency pair. Single elements, including tie-lines (see Section IV.A) from four other control areas in both Midwest ISO and PJM footprints were considered as the second (N-1) contingency in the contingency pair. Combining elements from the first control area with elements in second set of areas produced over 22,500 (N-1-1) contingencies.

Five reports, containing study results, are generated after each run:

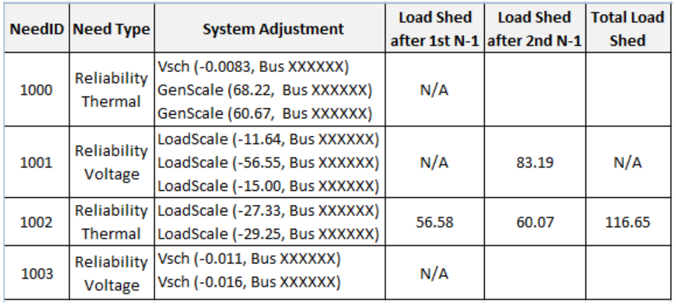
- AC Contingency Summary
- Contingency Details
- AC Branch Violations
- AC Voltage Violations
- Mitigation Plan

Reports “AC Contingency Summary” and “Contingency Details” describe (N-1-1) contingency pairs.

Report “AC Branch Violations” shows thermal overloads after each (N-1) contingency in the (N-1-1) contingency pair as well as cascading chains.

Report “AC Voltage Violations” lists post-contingency voltage range/deviation violations after each (N-1) contingency in the (N-1-1) contingency pair.

Report “Mitigation Plan” shows the details on system adjustments after each (N-1) contingency in the (N-1-1) contingency pair (see Section IV). It includes information on the type of adjustment that has been made, facilities that participate in the adjustment, and the minimum amount of mitigation measures needed to alleviate post-contingency violations. A partial view of report “Mitigation Plan” is shown in Fig. 5.



NeedID	Need Type	System Adjustment	Load Shed after 1st N-1	Load Shed after 2nd N-1	Total Load Shed
1000	Reliability Thermal	Vsch (-0.0083, Bus XXXXXX) GenScale (68.22, Bus XXXXXX) GenScale (60.67, Bus XXXXXX)	N/A		
1001	Reliability Voltage	LoadScale (-11.64, Bus XXXXXX) LoadScale (-56.55, Bus XXXXXX) LoadScale (-15.00, Bus XXXXXX)	N/A	83.19	N/A
1002	Reliability Thermal	LoadScale (-27.33, Bus XXXXXX) LoadScale (-29.25, Bus XXXXXX)	56.58	60.07	116.65
1003	Reliability Voltage	Vsch (-0.011, Bus XXXXXX) Vsch (-0.016, Bus XXXXXX)	N/A		

Fig. 5. A Sample “Mitigation Plan” Report

VI. FUTURE WORK

The following enhancements to the strategy are planned in the future:

- Priority List of units used in Generation Redispatch.

  Creating priority list of generators to be used in redispatch that take into account generator designation in the market: Network Resource or Energy Resource and associated cost.

  When generation is to be called upon to mitigate a constraint, consideration should be given to the least cost unit that would have sufficient sensitivity to the constraint to be effective enough.

  Similarly, when units are backed down, consideration should be given to turn off the most costly unit with sufficient sensitivity so as to be effective in mitigating constraint. When backing down generation, consideration should also be to its designation. Energy Resources should be backed down prior to backing down Network Resources.
- Probabilistic approach.

  Before ruling out a transmission upgrade as the more costly of the two alternatives when comparing with redispatch cost, consideration should be given to how many Category C3 events result in constraints that could be mitigated by either the transmission upgrade or redispatch. Probability associated with one pair would be low enough but increasing pairs would result in increasing probabilities and associated redispatch costs. A true probabilistic approach to planning that incorporates forced outage probabilities associated with outages as well as of generation availability would give a more comprehensive picture of the true cost of system adjustments.

VII. CONCLUSION

This present paper describes a process for performing N-1-1 contingency analysis as a part of NERC-compliance studies.

The proposed framework has the capability for large RTO's to perform exhaustive AC contingency analysis, both in terms of the speed of computations and the ability to handle large contingency lists.

The objectives of this study are:

- Perform exhaustive N-1-1 AC contingency analysis within Midwest ISO's footprint such that one element is located in one set of control areas while the second element is located in another set of control areas. These areas may located within Midwest ISO's or another RTO's (for example, PJM's) footprint.
- Identify various sets of system adjustments based on the type of violation and a contingency being applied (whether it's the first of the second contingency in the contingency pair).
- Analyze cascading outages.
- Report the results in an easy-to-use form.

The study shows that the proposed approach is a fast practical method for massive N-1-1 AC contingency analysis.

The benefits of the proposed framework include:

- Enabling both utilities and large RTO's to perform large-scale AC contingency analysis.
- Completely automating the process.
- Utilizing various sets of system adjustments within one computational run during massive AC contingency analysis.
- Accessing cascading outages as a part of massive AC contingency analysis.
- Providing flexible and comprehensive reporting.

The analysis is being performed using Midwest ISO's planning load flow data.

Midwest ISO used the software to evaluate over a million contingent events as part of the annual NERC TPL reliability assessment. All events were found to meet system performance requirements outlined in TPL standards and identified constraints had acceptable system mitigations identified consistent with the utilized algorithm.

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IX. BIOGRAPHIES

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