

Lesson Learned

Cascading Analysis Identifies Need for Pre-Contingent Load Shed

Primary Interest Groups

Transmission Operators (TOPs)
Transmission Owners (TOs)
Reliability Coordinators (RCs)

Problem Statement

A 138 kV line tree contact followed by the misoperation of a 345/138 kV transformer resulted in two contingency overloads. Upon performing cascading analysis, the entity realized that one of the contingencies could cascade if left unmitigated. The operator took action to shed load pre-contingent to prevent the possible cascade.

Details

Prior to the event, there were three planned outages in the area (see Figure 1: Reference Map). Outage #1 was in-place for over a month as part of a capital project to reinforce the area. Outages #2 and #3 occurred the morning of the event. Earlier, the RC issued a hot weather alert due to increased temperatures that day. Under those circumstances, TOPs consider deferring noncritical transmission work on the system. In this case, the RC and TOP ran the next day studies to assess the risk and determined that they were N-1 secure. There were no single contingencies that could cause a thermal, voltage, or stability issue on the system. Furthermore, Outages #2 and #3 were both considered recoverable within a few hours (if needed) as the work was to pour foundations under the lines.

Shortly after Noon, a 138 kV line tripped due to a tree contact (Outage #4). Simultaneously there was a misoperation (Outage #5) that tripped the 345/138 kV transformer at Substation B. Following the tree contact and the misoperation, there were no base case violations; however, there were two contingencies identified:

- 140% of emergency rating on the 138 kV line from Substation D to Substation E for the loss of the 345/138 kV transformer at Substation A
- 132% of emergency rating on the 138 kV line from Substation D to Substation E for the loss of the 138 kV line from Substation A to Substation C

No controlling actions were available, so a cascade analysis began.

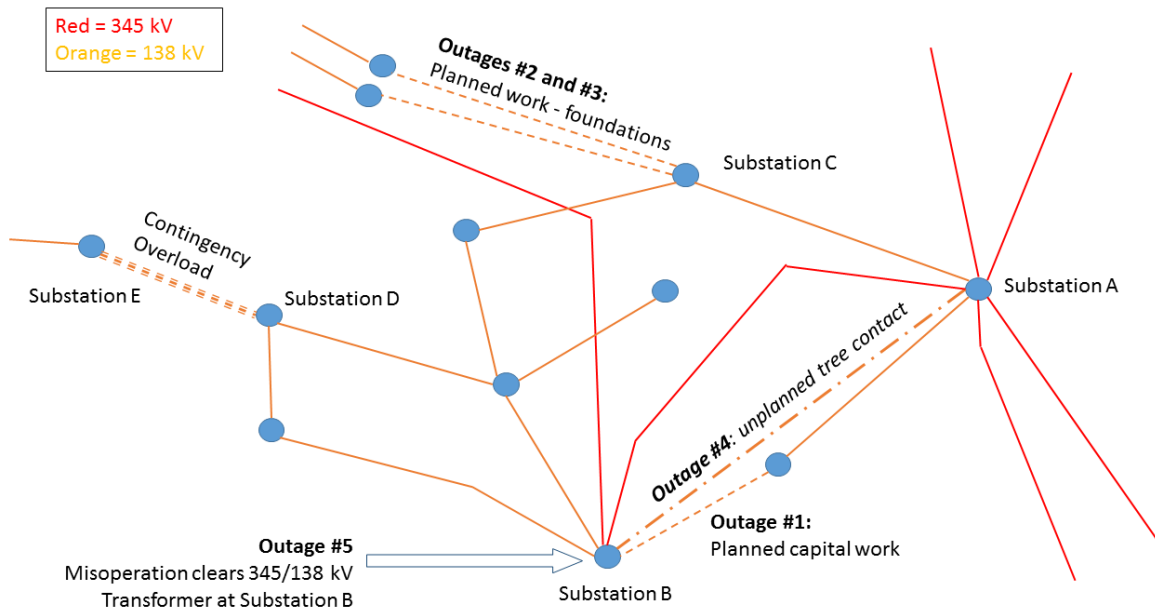


Figure 1: Reference Map

At first, the TOP and RC did not agree on the contingency results (see Figure 2: TOP View vs. RC View). Because there was a capital project (in-progress) to reconfigure Substation B, the energy management system (EMS) models were not consistent. The TOP and RC operators quickly resolved the issue over the phone as the TOP explained that the misoperation tripped the 345/138kV transformer. The RC operator manually toggled the 138 kV transformer disconnect switch open in the model, and then they agreed on the contingency results.

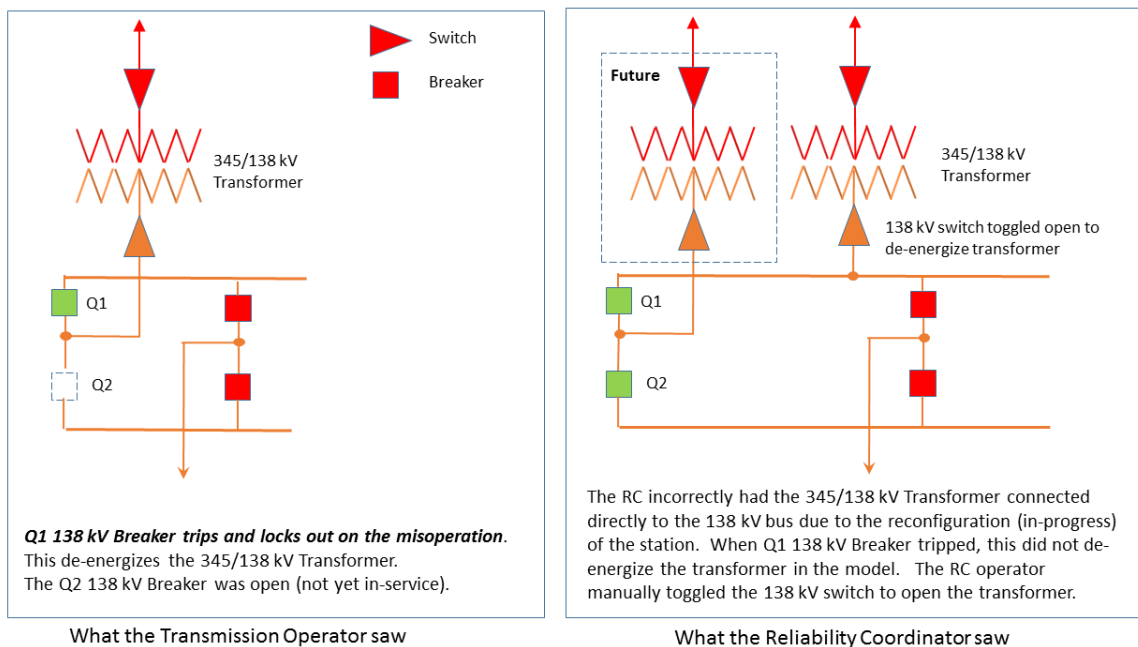


Figure 2: TOP View vs. RC View

As per the RC's cascade analysis procedure, the RC ran additional studies to determine if a cascade would occur if either contingency were to happen. If the contingencies that were identified were to occur, the lines would have overloaded to the point that they may have tripped soon after. The RC ran an offline study where they study if the contingency happened and then manually opened overloaded lines (assuming they would sequentially trip) to see if the condition was local (bounded) or widespread (cascades). Upon this review, the RC determined that the loss of the 138 kV line from Substation A to Substation C coupled with the loss of the 138 kV line from Substation D to Substation E would possibly cascade.

Corrective Actions

The RC and TOP began taking emergency actions to preserve the reliability of the system upon studying the contingencies and the possibility of cascade. There were no generation options for a re-dispatch so they took the following actions:

1. The TOP recalled the two recoverable outages (Outage #2 and #3) to bring those 138 kV lines back into service.
2. The TOP sent personnel to the 138 kV line from Substation A to Substation B to recover the line (Outage #4) and to Substation B to investigate the transformer misoperation (Outage #5).
3. The RC issued a load shed directive to shed 21 MW of load to reduce the contingency flow.
4. The TOP received the load shed directive and shed 21 MW of load.

Shortly after taking the corrective action to shed the load, the 345/138 kV transformer at Substation B was recovered. The RC and TOP re-reviewed the contingency results and determined that load could be restored. Load was restored and the other outages (Outages #2, #3, and #4) were recovered shortly after as well.

The TOP reviewed the circumstances regarding the transformer misoperation. It was an unnecessary trip during a fault condition (the fault was the tree contact on the 138 kV line from Substation A to Substation B). The phase instantaneous overcurrent element picked up for a reverse fault due to the directional settings. The settings were not considered incorrect as they were auto-calculated by the relay manufacturer but had a forward-looking bias, meaning that, under certain circumstances, the relay may detect a reverse fault in the forward-looking direction before it recognizes that the fault is behind it. The existing settings were more dependable than secure. The new settings were auto-calculated with new guidance from the relay manufacturer that removed the forward-looking bias and made the settings more secure.

Furthermore, there is a capital project (in-progress) to reconfigure the 345 kV yard at Substation B to add a ring bus so the 138 kV breaker's relaying does not have to protect both the 345/138 kV transformer and the 345 kV line. The existing configuration has the transformer tapped off of the 345 kV line without a dedicated 345 kV breaker.

Lessons Learned

While the operator took the proper action to shed load to preserve the reliability of the system, there were some lessons learned from this event, including recommendations for enhanced performance.

- TOs should consider enhancing vegetation management procedures to include a review and inspection of facilities that are near their trimming cycle and potentially impacted by nearby maintenance outages. Before taking a long non-recoverable outage, TOs may want to assess nearby facilities for vegetation risks.
- Review auto-calculated relay settings that may have a forward-looking bias. Work with the relay manufacturer as needed to determine which relays may be impacted following new guidance documents that are posted.
- Identify additional controls to help ensure that the TOP's and RC's EMS models accurately align, especially during multi-phased reconfiguration and construction projects. Often the TOP can update its EMS model more frequently than the RC can update its model, so communication is important to notify the RC of the status of the work.
- Work with the EMS vendor to enhance cascade analysis alarming, visualization, and (if possible) automation of this process to increase situational awareness.
- Consider running additional studies (beyond N-1 criteria) during a hot weather alert before taking non-emergency outages. In this particular case, a N-1-1 study would not have revealed any overloads (as Outages #4 and #5 did not result in any base-case violations); however, the RC is investigating software approaches to run additional studies during a hot weather alert.
- If there are recoverable outages ongoing during a hot weather alert, consider pre-staging personnel and equipment needed for recovering from the outages at the locations they would be needed with detailed step-by-step recovery instructions. This can minimize the time required for restoration.

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