Effective Use of Incipient Failure Detection

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Introduction

Distribution circuits historically have operated in a largely reactionary mode: build strong circuits, using materials that generally last for decades; run to failure; make repairs. With limited exceptions, such as frequent inspection of key components, circuit owners lack practical alternatives.

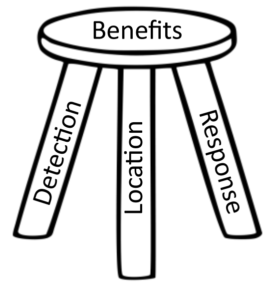
Many line components last for decades, but eventually they fail. Applied research by Texas A&M Engineering, working collaboratively with more than twenty circuit owners and using data from circuits during routine operations, shows that some component failures have incipient failure periods, often measured in hours, days, weeks, or even months, during which they manifest electrical precursors. Conventional methods and technologies, however, leave circuit owners blind to those incipient failures.

Certain incipient-failure conditions now can be detected and located, but achieving practical benefits requires effective business-as-usual response procedures. This paper uses case studies from in-service distribution circuits, some cases realizing benefits and others representing missed opportunities, to illustrate the need for development of appropriate response procedures.

Incipient Failures – A Practical Definition

***Incipient**: adj. beginning to come into being or to become apparent* (Meriam-Webster online dictionary)
A common belief holds that incipient failures of line apparatus manifest only low-magnitude electrical currents, and the companion implication that any condition that manifests high-magnitude current therefore is not incipient. Based on substantial applied field experience, the authors disagree and offer the following practical definition of an incipient failure. An incipient failure is any degenerating condition that, if left uncorrected, will result in a negative outcome in the future. The definition contains no dependence on current or voltage magnitude. Many incipient failure conditions indeed do manifest low-magnitude current, but many others manifest high-magnitude current. This paper describes real-world case studies of both types. All cases reviewed in this paper, whether low-current or high-current, involved electrically detectable incipient conditions that were not made actionable by conventional monitoring and protection systems.

Incipient Failures Can Be Detected – Now What?



Benefitting from incipient failure detection requires three elements: the detection itself, location, and response. Using sophisticated monitoring, many incipient failures now can be detected, some with specificity as to the nature of the failure (i.e., discriminate a failing cable from a failing switch from …). Further, some can be located, either with great specificity or in terms of targeting inspection to a limited portion of a circuit. To benefit from these new capabilities, though, the circuit owner must have appropriate processes for: timely review of detection reports (i.e., pay attention); use of available resources (e.g., circuit models, smart meter data, …) to determine or approximate location; and dispatch of appropriate personnel. Without action, knowing an incipient failure exists, and perhaps even knowing its location, yields limited benefit.

Historically, companies have developed procedures based on technologies available at the time and then modified those procedures as technologies improve. The advent of new forms of information, such as detection of incipient failures, requires willingness to rethink response processes. Case studies that follow illustrate effective use of incipient failure detection and, by contrast, cases of unrealized benefit.

Case Studies

The following case studies review apparatus failures and response processes that were documented as part of Texas A&M Engineering's Distribution Fault Anticipation (DFA) work. Each focuses primarily on how circuit owners acted on incipient-failure reports, not on the incipient-failure detection method.

An Aside: What is Series Arcing?

The underlying incipient failure in multiple case studies that follow is a phenomenon referred to as series arcing. Unlike shunt arcing, series arcing does not cause current to flow in an unintended path. Rather, series arcing occurs because elevated, often unstable impedance interferes with normal flow of load current. Typically this elevated impedance occurs because of progressive degradation in the contact surfaces of a current-carrying device, such as a hotline clamp, a switch, or a jumper connection. Figure 1 illustrates this graphically. Photographs accompanying the narratives of case studies 1 and 1b show physical manifestations of series arcing. The key point is that shunt and series arcing are very different phenomena and behave differently electrically, and the monitoring system software differentiates between the two types.

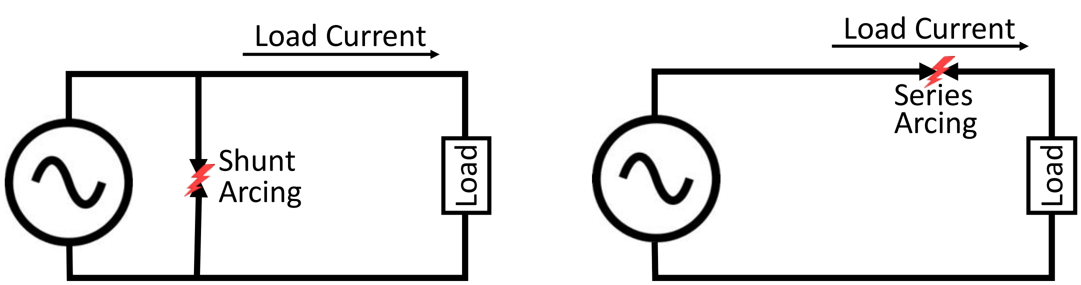


Figure 1. Contrast between shunt and series arcing

Case Study 1: Failing Jumper with Preemptive Action to Avoid Final Failure

This event involved series arcing in a jumper connection to a single-phase poletop transformer on a 24.9 kV, four-wire distribution circuit. The solid-copper jumper connected a primary phase conductor to the primary bushing of the transformer and attached to a surge arrester at the mid-point of the jumper. The copper jumper broke at the point of attachment to the arrester, but the jumper's stiffness caused it to maintain contact and continue providing service. The single customer served by the transformer did not report flickering lights, blinking lights, or outage. The circuit owner's sole notice of the event came from the DFA monitor at the substation head of the circuit. The circuit has 54 line-miles of primarily overhead conductor, and the incipient failure condition occurred 7.5 circuit miles from the substation. Figure 2 provides a photograph of the arcing jumper and associated apparatus. Figure 3 shows ten seconds of RMS current data that the monitoring system recorded, via circuit CTs at the substation, during a flareup of the arcing event, and illustrates the current magnitude's minimal rise above normal load level.

Because series arcing interferes with normal flow of load current but does not draw fault current, per se, model-based location is inherently unsuitable for series arcing. The circuit owner had been using the monitoring system for several years, had responded to several alerts to series-arcing failures, and had developed a procedure to use their power line carrier (PLC) based meter system to locate series arcing. PLC uses the power line itself as the communications medium, and series arcing can prevent the failing device from conducting bidirectional communications between meters and the PLC controller at the substation. The series-arcing phenomenon tends to flare up for seconds to minutes but also has quiescent periods that can last minutes to hours or even days. The monitoring system provides real-time (i.e., within a minute or so) indications of active flare-ups. The location process involves issuing PLC-based "ping" requests to meters at times when the monitoring system indicates series arcing is active. Although meters beyond the failing device remain ON and serving customers, the series arcing prevents communications, so those meters fail to respond to ping requests. After performing this ping process, the company looks at current-carrying connections just upstream of those meters. Because of the intermittency of series arcing, it may be necessary to repeat the ping process more than once to find a meter or cluster of meters that (falsely) ping OFF.

In the subject case, the company followed that procedure. When the monitoring system reported a period of active series arcing, an operator initiated a ping request to all meters on the indicated phase of the subject circuit. A single meter failed to respond, thereby targeting crew response to the primary connection of that meter. The company timely dispatched a lineman, who found the arcing condition of Figure 2. The specific transformer was known, making location straightforward and efficient.

This case demonstrated ideal response to an incipient failure. The monitoring system reported an incipient failure, and specifically reported it as a series-arcing failure. The circuit owner had in place and executed an effective location process. Finally, they responded in a timely fashion. This satisfied all three requirements and achieved positive outcome. No customer experienced an unplanned outage, and the duration of the outage required for performing the repair was minimized, because the line crew already was on site and had diagnosed the problem, before disconnecting the customer to effect repairs.

A key point of this case study is that the circuit owner used past experiences to develop a business-as-usual process for locating the failure and dispatching field response, upon notice of the incipient-failure condition from the monitoring system.

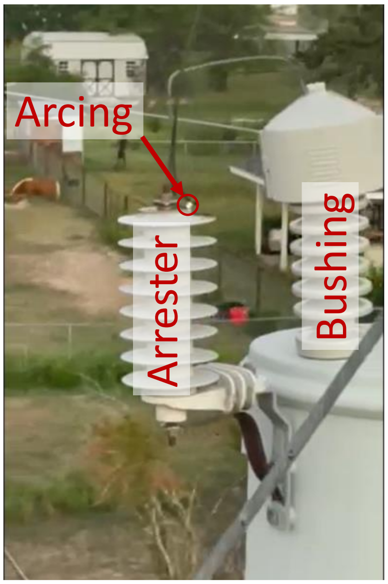


Figure 2. Failing jumper, arcing but providing service, without customer complaint (case study 1)

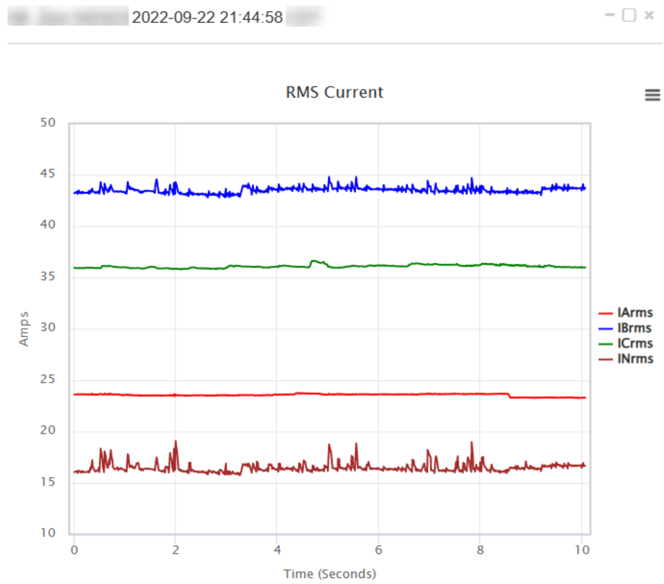


Figure 3. Substation-based RMS current during condition of Figure 2 (current = load + event)

Absent detection-enabled preemptive response, the outcome of this specific case likely would have been an outage to a single customer, but it is appropriate to extrapolate. The Texas A&M research team has documented cases of series arcing in connections serving hundreds. For example, in another case, the monitoring system detected series arcing in a substation switch, that detection prompting successful response to locate and correct the incipient failure. Full failure would have caused, at a minimum, a lengthy outage to at least one complete circuit. Further, series arcing progressively erodes the failing connection's contact surfaces. Whether such a connection serves one customer or thousands, erosion over time may break conductors and even result in a downed, energized conductor.

Case Study 1b: Another Failing Jumper with Preemptive Action to Avoid Final Failure

This case study is almost identical to case study 1 and therefore is labeled as 1b. It again involved a failing, solid-copper jumper to a single service transformer on a 24.9 kV four-wire circuit. The circuit has 69 miles of primarily overhead construction, and the incipient failure was 4.4 electrical miles from the substation. The circuit owner is the same for case studies 1 and 1b.

The detection, location, and response procedures again produced the desired benefit: the substation-based monitoring system provided the circuit owner's sole notice and informed them that the incipient failure involved series arcing; the circuit owner used the PLC-based meter system to locate the specific transformer, prior to dispatching a crew; and the crew efficiently located the problem and made repairs without an unplanned outage or other consequence to the system or to the customer.

The photograph of Figure 4 attempts to show the arcing at the point of failure between the jumper and the bushing, though the visible sign of arcing is minimal, making it difficult to see. Figure 5 shows ten seconds of RMS current and deserves comment. The monitoring system resides at the substation, so its measurements and therefore the graph represent normal load current plus current variations caused by the incipient-failure series arcing. The subject service transformer is connected phase-to-ground on phase C, and the series arcing affects only that phase current and the neutral (3Io) current. Load on phase B, which is unaffected by the series-arcing condition, causes more current variation than the series arcing on phase C. In other words, one of the healthy phases shows more current variation than the phase with the incipient failure. Variations in both phase currents appear substantial, but that is largely because the circuit's load current is very low, less than 20 amperes. The monitoring system's software uses digital signal processing techniques that trigger on small electrical variations, even in cases with load current of hundreds of amperes, instead of just a few tens of amperes. The software also discriminates between various types of incipient-failure signatures, in this case series arcing, even when a few amperes of incipient-failure signature is masked by hundreds of amperes of load.

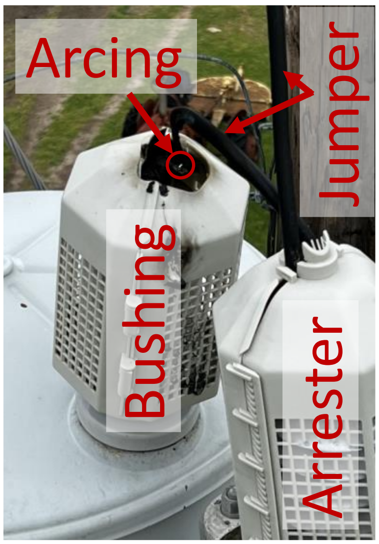


Figure 4. Another failing jumper, arcing but providing service, without customer complaint (case study 1b)

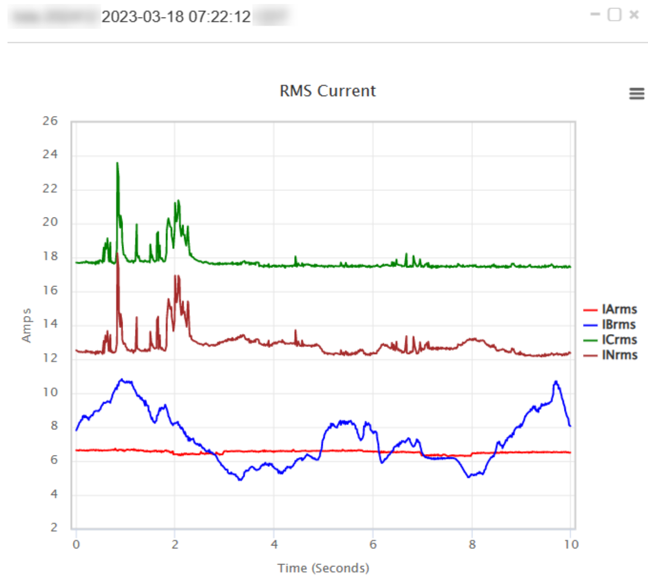


Figure 5. Substation-based RMS current during series-arcing incipient-failure condition of Figure 4 (current = load + event)

Case Study 2: Failing Jumper – Unrealized Benefit Resulting from Process Failure

In case studies 1 and 1b, new business-as-usual detection, location, and response processes, designed to take advantage of the new capability to detect incipient failures, resulted in avoidance of a final failure. In case study 2, the detection and location requirements functioned properly, but the circuit owner did not have a business-as-usual process for timely field response. Consequently, the condition went to final failure more than two weeks after it had been detected and its location pinpointed.

Case study 2 again involved series arcing, again arising from a jumper connection to a single-phase poletop transformer, this time on a 12 kV distribution circuit. The jumper connected the primary phase conductor to the primary bushing of the transformer and failed at the point where it attached to the bushing. The two customers served by the transformer did not report flickering lights, blinking lights, or outage, until the jumper fully separated, eighteen days after the series arcing began. Prior to final failure, the circuit owner's sole notice of the event came from the DFA monitor at the substation head of the circuit.

Series arcing often exhibits substantial intermittency, as the timeline of Figure 6 illustrates for the subject case study. In the figure, each column represents the number of times the substation-based monitor for the circuit detected the incipient, series-arcing condition, per hour. The failure timeline runs eighteen days. During the first three days, and then again during the last three days, many hourly intervals had dozens or even hundreds of series-arcing episodes. Days four through fifteen, however, had relatively few episodes, with many hours having none. This type of intermittency is fully consistent with many series-arcing cases that the Texas A&M Engineering team and host companies have experienced.

The circuit owner became aware of the condition shortly after it began, and then, using their AMI (advanced metering infrastructure) meters, they determined one specific transformer as the probable location of the incipient, series-arcing failure. This circuit owner was newer to the use of the monitoring system and previously had not had the capability to detect series arcing, so they did not have a business-as-usual process for responding. Consequently, the monitoring system detected the condition, specifically as series arcing, and the AMI system pinpointed the location of the incipient failure, but the circuit owner failed to respond in a timely manner, leaving the condition to proceed to final failure.

This circuit owner has meters with different capabilities than those of the circuit owner of case studies 1 and 1b. Their meters communicate via wireless communications, not PLC, so their process to use meters to locate series arcing was different. That said, this circuit owner's meters gave clear indication of location, shortly after the initial series-arcing report and during flare-ups during the eighteen-day course of the failure.

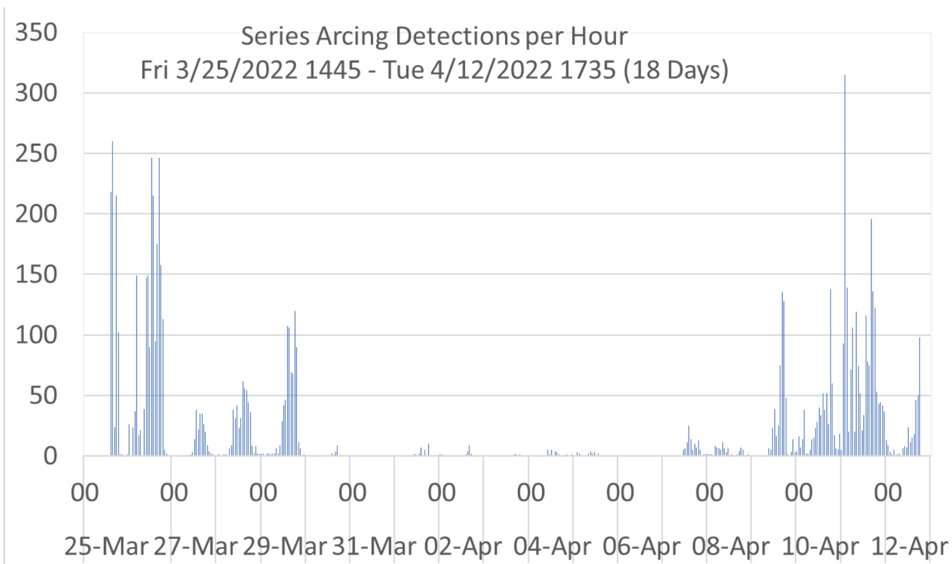


Figure 6. Timeline of Case Study 2, illustrating intermittency typical of series arcing

Texas A&M Engineering works with circuit owners that use PLC-based metering and circuit owners that use RF-communicating meters. That experience show that RF-communicating meters' response to series arcing varies substantially by make and model. Specifically, some have good sensitivity to voltage variations that manifest on services downstream of series arcing, whereas others have less sensitivity to those variations. Texas A&M Engineering engages in collaborative projects with users of the monitoring technology, to investigate best practices for synergistic use of the DFA monitoring system with each circuit owner's other tools, such as smart meters, to optimize results for that circuit owner.

Contrasting Case Studies 1, 1b, and 2

These three case studies had uncanny similarities. Each involved an incipient series-arcing failure between a jumper and the primary bushing of a single service transformer. None caused a complaint by customers served by those transformers (except the outage of the final failure of case study 2). Each circuit owner used its meter system to pinpoint the series arcing. The only meaningful difference was the response leg of the stool: one circuit owner had used the monitoring system for a longer period and had in place a process for timely field response, whereas the other did not have a process and consequently did not respond to avoid the final failure.

Case study 2 went to final failure eighteen days after initial detection by the monitoring system, that period consisting of highly active periods intermingled with periods of little or no activity. Case studies 1 and 1b were resolved within a day. It cannot be known how long, absent incipient detection, those case studies would have persisted prior to final failure or complaint by a customer. Texas A&M Engineering's experience, based on collaborative, multi-year efforts with several dozen circuit owners, has been that incipient series-arcing failures can persist for weeks or go to final failure in hours. Detection, location, and field response inherently take time. Some failures proceed to final failure too quickly for a pre-failure response to be feasible, but others provide adequate response time, particularly if business-as-usual response procedures have been designed and put in place in advance.

Case Study 3: Failing Vacuum Switch with Preemptive Action to Avoid Final Failure

The series-arcing case studies above involved incipient failures that manifested low-magnitude currents. By contrast, case study 3 involved high-magnitude pulses, arising from incipient failure of a vacuum switch that was part of a switched, ungrounded line capacitor on a 16 kV distribution circuit.

The vacuum switch was beginning to experience partial loss of vacuum. The fundamental principle for vacuum switching is that near-total vacuum provides much better electrical insulation than normal air, with the beneficial result being that contacts in a vacuum switch can be very close together, while in the open position, and travel distance for the movable contact can be short. If a vacuum switch loses even partial vacuum, though, the small inter-contact separation can fail to interrupt current or even to hold line voltage effectively and consistently.

The DFA monitoring system at the substation head of the subject circuit detected more than 200 phase-to-phase current pulses over a period of 44 days. Each pulse had peak magnitude of many hundreds of amperes, some exceeding 1000 amperes, but their durations were too short to blow capacitor fuses or operate other protection. In general, as a capacitor switches OFF, switch contacts experience elevated voltage stress. Current interruption occurs when current naturally passes through zero. Because the current is capacitive, interruption at current zero means interruption at voltage peak, leaving peak line voltage trapped on the capacitor. One-half cycle later, line voltage again peaks, but with opposite polarity, resulting in twice line voltage across the contacts. It is at these opposite-polarity peaks, soon after the switch opens, that capacitor switch contacts are most vulnerable to restrike.

In the present case study, some of the pulses occurred as the subject capacitor bank switched OFF, and the DFA monitoring system software auto-reported those specifically as capacitor restrike. The failing switch also manifested many pulses while the bank was OFF and not in the process of switching, and the DFA monitoring system auto-reported those as short-duration faults or generic shunt arcing events. Figure 7 provides a partial list of the auto-reported restrike episodes, and Figure 8 shows the substation-recorded voltages and currents during one of the episodes. The bank is ungrounded, and the circuit owner uses only two switches, leaving the third phase always connected, so each restrike in the compromised switch caused a phase-to-phase current pulse.

The episodes that were labeled specifically as restrike alerted personnel that a capacitor switch was failing. The circuit owner has a central dispatch system for its capacitors, making it straightforward to correlate times of DFA-reported restrikes with switching times from the central dispatch controller log, a process that readily identified a specific bank. Field response then replaced the bank, after which the monitoring system confirmed that removing the bank had resolved the problem (i.e., pulses ceased upon bank removal).

In the subject case, the monitoring system provided detection, and correlation with the circuit owner's capacitor switching log provided location. The field response in this case was ad hoc but successful, taking 44 days to remedy the incipient failure but avoiding any escalation that otherwise might have occurred. Doing something for the first time informs development of business-as-usual processes, which in turn can lead to faster response for future events.

2022-07-24 21:49	Capacitor restrike (severe)
2022-07-23 00:19	Capacitor restrike (severe)
2022-07-18 18:49	Capacitor restrike (severe)
2022-07-17 00:19	Capacitor restrike (severe)
2022-07-14 23:49	Capacitor restrike (severe)
2022-07-13 07:49	Capacitor restrike
2022-07-04 00:49	Capacitor restrike
2022-07-01 19:19	Capacitor restrike (severe)
2022-07-01 04:49	Capacitor restrike (severe)
2022-06-30 13:19	Capacitor restrike
2022-06-29 19:49	Capacitor restrike
2022-06-29 05:49	Capacitor restrike
2022-06-28 14:49	Capacitor restrike (severe)
2022-06-27 20:19	Capacitor restrike (severe)
2022-06-27 03:19	Capacitor restrike
2022-06-24 16:19	Capacitor restrike (severe)
2022-06-23 18:49	Capacitor restrike (severe)
2022-06-21 17:54	Capacitor restrike
2022-06-21 07:54	Capacitor restrike
2022-06-20 21:54	Capacitor restrike (severe)
2022-06-17 15:54	Capacitor restrike (severe)
2022-06-15 22:46	Capacitor restrike
2022-06-11 19:46	Capacitor restrike

Figure 7. Capacitor vacuum pulses auto-labeled as restrike (case study 3)

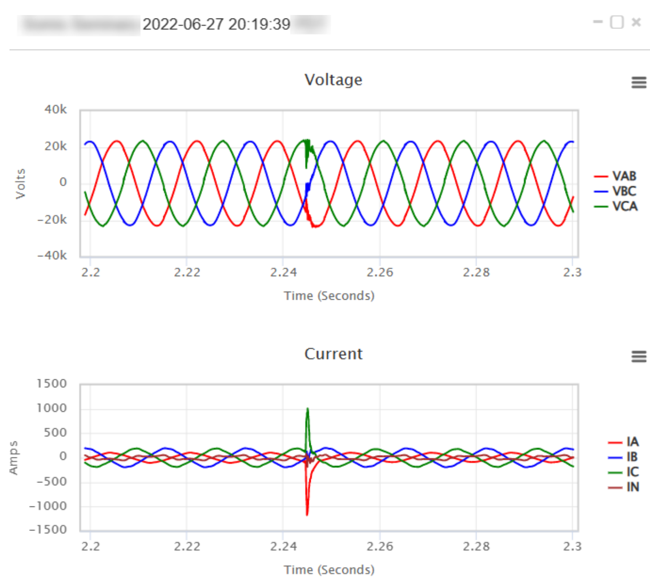


Figure 8. One restrike pulse resulting from partial loss of vacuum in the capacitor switch (1000 amps, 1 millisecond)

Case Study 4: Vegetation-Caused Line Burndown – Unrealized Benefit

This final case study represents a missed opportunity and resulted in a line burndown after an incipient period that lasted two years. It occurred on an 11 kV, three-wire circuit and was caused by trees.

Under normal conditions, the offending trees did not cause trouble, but under wind conditions, they repeatedly pushed conductors together, creating phase-to-phase faults. The repeated faults were at the same location, so they drew the same magnitude of fault current and tripped the same recloser, which then auto-reclosed after 5.5 seconds. This sequence occurred several times during a given storm and then repeated during the next storm. Each episode was a high-current precursor to the final burndown. Figure 9 illustrates the fault, trip, and auto-reclose for one precursor event in 2016, one precursor event in 2017, and the final burndown in 2018. In that two-year period, there were a total of 44 precursors, plus the final event. Prior to the burndown event, there were many momentary interruptions but no sustained outages, and the circuit owner's business-as-usual processes did not take note of the "cluster" of recurring events.

Monitoring system software automatically characterizes and reports each individual fault, including reporting on the response of the protection system (fault duration, magnitude, phases, amount of load interrupted, open duration prior to auto-reclose). Beyond that, it maintains a history of faults and examines it to identify clusters of similar "recurrent faults." This clustering capability was implemented because of observations that multiple types of incipient-failure conditions cause intermittent, recurring fault events at the same location, and that these faults will have similar characteristics that can be clustered together by software and reported to users for review and action. The clustering function is critical, because unrelated faults occur and mask the cluster. Given sufficient time and skilled resources, a dedicated circuit owner theoretically could analyze every fault on their system to find clusters, but few if any do so. The subject case is instructive. In a two-year period, the circuit experienced 178 faults, 44 from the incipient-failure condition and 134 unrelated. The circuit owner's communicating reclosers recorded all 178, but business-as-usual practices did not draw attention to the important cluster of 44.

Figure 9. Two precursors (2016, 2017) and the resulting final burndown event (2018)

Detecting an incipient failure is the without-which-nothing for curing it, and the monitoring system provided detection in the form of a report of numerous software-clustered faults. The precursor events are bolted phase-to-phase faults, so they produce current magnitudes generally well suited to location with the use of circuit model software. In addition, the circuit owner had communications to the auto-recloser that was operating, enabling definite knowledge of which recloser was operating at each time indicated in the monitoring-system cluster report. The circuit owner was evaluating the monitoring technology in a "blind study" mode, though, and therefore did not take action to locate or respond to the reports, instead letting events play out as they would do without the monitoring system. The result was a line burndown on the forty-fifth tree-induced contact event in a period of two years, a result that speaks volumes about the difference between having data (i.e., fault records) and information (i.e., a software-generated cluster of recurrent faults).

Key Takeaways from Case Studies 3 and 4

There are two points to be made from the high-magnitude events of case studies 3 and 4: incipient failures are not synonymous with low-magnitude events, and relays and their equivalents may detect individual high-current events but fail to provide effective notice of incipient conditions. Recall this paper's earlier discussion of what constitutes an incipient failure, and specifically that the term incipient does not depend on current magnitude. Case studies 3 and 4 provide examples of high-current incipient-failure conditions. Each illustrated an incipient-failure condition that, left uncorrected, would lead to problems in the future; indeed case study 4 was not acted upon and resulted in a broken conductor. The precursor signals for each were high-magnitude currents, measuring many hundreds of amperes and detectable, as individual events, by relays and their equivalents. In both cases, relays were in place and presumably detected each precursor event, but in neither case did they notify the circuit owner that an incipient condition existed and required response. This latter concept is important, because it is natural for practitioners to recognize that existing relays often trigger and record individual high-magnitude events and to extrapolate that to a belief that they "have those events covered" with existing systems. The Texas A&M Engineering applied R&D program, however, has documented large numbers of cases, including case studies 3 and 4 herein, where those existing systems failed to raise any effective notice for high-current events. Having raw data does not generate awareness.

Summary of Case Studies

Table 1 summarizes the case studies reviewed herein. Some cases manifested low-current anomalies; others manifested high current. Conventional business-as-usual processes did not alert the circuit owners to any of them, but the specialized monitoring system alerted all of them. All were locatable, using circuit owners' other tools. Benefit was realized in cases where circuit owners paid attention to alerts, chose to act, and had processes in place for timely response. The salient point is that some incipient-failure conditions now are actionable, but realizing benefits requires willingness and work to create and implement new business-as-usual processes that can realize benefit from this new capability.

Case	Description	Current	Conventional Alert	Incipient Detection	Located	Responded To	Benefit Realized
1, 1b	Series arcing, xfmr jumper	Low	No	Yes	Yes	Yes	Yes
2	Series arcing, xfmr jumper	Low	No	Yes	Yes	No	No (Outage)
3	Cap vacuum switch	High	No	Yes	Yes	Yes	Yes
4	Vegetation	High	No	Yes	No	No	No (Broken Conductor)

Table 1. Summary of case studies

Source Data for Case Studies

Although this paper's focus is on the need for effective response procedures, the authors would be remiss if they failed to provide a brief explanation of the monitoring system and features important to detection of incipient failures. Texas A&M Engineering's applied research team initially sought to use relays or other suitable off-the-shelf platforms to provide data for this purpose, but they were unable to find any that met all or even most requirements. All electrical recordings used in the case studies cited herein come from a bespoke platform Texas A&M Engineering's research team specified for performing the DFA function:

1. Substation-based monitoring, one monitoring device per distribution circuit
2. Conventional current and potential transformers (CTs and PTs) as inputs
3. Continuous monitoring at 256 samples/cycle*

4. Unconventional, sensitive triggering (not just simple current, voltage, or harmonic thresholds)
5. Extended-duration recordings (10-60 seconds typical)
6. Automatic algorithmic processing to diagnose problems and produce reports
7. Automatic timely retrieval of reports and data to a central Master Station, for access by personnel
8. Distributed processing, in which each monitor acquires its circuit's data continuously, triggers, records anomalies, runs algorithms on those recordings, creates reports, and sends those reports to a central server for user access, rather than sending bulk data to a central server for algorithmic processing and report generation. (This specification is not conceptually necessary for detecting incipient failures but rather a choice for practical application.)

* When an electrical signal anomaly causes the monitoring platform to trigger, the platform records currents and voltages at 256 samples/cycle. Some graphics shown herein display RMS quantities (one value/cycle), because RMS often provides better understanding than high-speed sinewaves, particularly for long-duration records, but the underlying data remains available at 256 samples/cycle.

Sensitive triggering is without-which-nothing for detecting the low-magnitude current and voltage variations that result from certain types of incipient failures (not all types). Sensitive triggering results in significant numbers of recordings, which necessitates automatic processing, without human intervention, to enable effective, timely use of the information.

Conclusions

Recent technology advances make it possible to detect and respond to incipient faults that were not detectable at the turn of the century. These new capabilities provide practical benefit to circuit owners only if an incipient failure can be detected, located, and responded to, all in a timely manner.

Texas A&M Engineering conducted the applied research and development of the Distribution Fault Anticipation (DFA) technology that detected the incipient failures reviewed in this paper. They continue to work collaboratively with multiple utilities and other circuit owners to investigate best practices for synergistic use of other data sources, including without limitation circuit models, AMI, and distributed sensors, to locate incipient failures that the DFA system detects. Circuit owners are using that collaborative interaction to implement business-as-usual processes to realize benefits from the new capabilities.