SANDIA REPORT
SAND2022-0208
Printed January 2022

Sandia National Laboratories

Roadmap for Advancement of Low-Voltage Secondary Distribution Network Protection

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ABSTRACT

Downtown low-voltage (LV) distribution networks are generally protected with network protectors that detect faults by restricting reverse power flow out of the network. This creates protection challenges for protecting the system as new smart grid technologies and distributed generation are installed. This report summarizes well-established methods for the control and protection of LV secondary network systems and spot networks, including operating features of network relays. Some current challenges and findings are presented from interviews with three utilities, PHI PEPCO, Oncor Energy Delivery, and Consolidated Edison Company of New York. Opportunities for technical exploration are presented with an assessment of the importance or value and the difficulty or cost. Finally, this leads to some recommendations for research to improve protection in secondary networks.

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EXECUTIVE SUMMARY

The purpose of this investigation is to assess the electric utility and commercial customer experience with low-voltage (LV) distribution network protection devices and systems. It reviews various technical specifics that characterize the current state of utility and commercial LV network distribution interface products and applications and presents a range of design ideas for improvements and additions. This leads to a concise, prioritized list of recommended research and development topics for this old and stable technical domain.

This report summarizes well-established methods for the control and protection of LV secondary network systems and spot networks, including operating features of network relays. While highly reliable schemes have evolved over a century, there are unprotected zones in some configurations, and spectacular events of uncleared faults and facility burndowns have occurred. Furthermore, the simple directional protection schemes clash with distributed energy resources (DER) installations within the protected LV network. The network was not conceived for the altered energy flow and fault-current patterns of DER or normal steady-state reversal of power flow direction back into the high-voltage grid that once supplied all the energy. The physical nature of network transformer vaults buried under streets in challenging physical environments has made it difficult and costly to install communications for continuous or centralized status monitoring or control of power apparatus and relays, limiting situational awareness of service status or impending failures.

The following report chapters begin with fundamental principles of LV network application and protection, along with industry practices and experiences, followed by an assessment of trends and expected future changes in operating conditions and requirements. From this framework, the report proposes improvements to familiar methods and new solutions to eliminate existing shortfalls. It concludes by listing development project opportunities comprising a roadmap for developing new protection and control (P&C) designs for these networks.

Further development and testing of LV network P&C, with its MV supply systems, depends on modeling tools which in turn can benefit from new development, both for accuracy of modeling existing components and for the ability to properly model the behavior of new components like inverter-based DER in normal operations and fault or switching conditions. These tool study and development opportunities are strong candidates for further development.

ACRONYMS AND DEFINITIONS

Abbreviation	Definition
ADMS	advanced distribution monitoring system
AMI	advanced metering infrastructure
AP	access point
BESS	battery energy storage system
DER	distributed energy resources
DERMS	DER management system
EM	electromechanical
FLISR	fault location, isolation, and service restoration
GSR	ground-sensor relay
HV	high voltage
IED	intelligent electronic device
IEEE	Institute for Electrical and Electronics Engineers
IR	infrared
IT	instrument transformer
LV	low-voltage
MCOT	magneto-optic current transducer
MV	medium-voltage
NP	network protector
NREL	National Renewable Energy Laboratory
P&C	protection and control
PLC	power-line carrier
PSRC	Power System Relaying Control
RMS	remote monitoring system
RTAC	real-time automation controller
SCADA	supervisory control and data acquisition
SNL	Sandia National Laboratories
SOS	structural observation system

1. INTRODUCTION

The purpose of this investigation is to assess the electric utility and commercial customer experience with low-voltage (LV) distribution network protection devices and systems. It reviews various technical specifics that characterize the current state of utility and commercial LV network distribution interface products and applications. Also, it presents a range of practical or far-reaching design ideas for improvements and additions. This information leads to a concise, prioritized list of recommended research and development topics for this technical domain.

For nearly a century, LV distribution networks have provided reliable electric power to concentrated loads such as office buildings in densely populated urban or commercial areas. Equipment protection within the network vaults typically has simple and limited functionality. Historically, users have depended upon the physical design of the vault to limit the risks of fault damage for faults within the vault. They have relied upon remote medium-voltage (MV) detection and interruption for transformer faults, while LV devices such as transformer fuse links and LV cable limiters provide a measure of LV bus fault protection. Rare but spectacular major failures can impact public safety and service continuity in these densely populated customer locations.

This report summarizes well-established methods for the protection and control (P&C) of LV secondary network systems and spot networks, including operating features of network relays. These simple directional protection schemes clash with distributed energy resources (DER) installations within the protected LV network. The network was not conceived for the altered energy flow and fault-current patterns of DER or normal steady-state reversal of power flow direction back into the high-voltage grid that once supplied all the energy.

Furthermore, the physical nature of network transformer vaults buried under streets in challenging physical environments makes it difficult and costly to install communications for continuous or centralized status monitoring or control of power apparatus and relays. As a result, there is limited situational awareness of service status or impending failures. Some utilities now find schemes for communicating with network transformers and relays.

The following report chapters begin with fundamental principles of LV network application and protection, along with industry practices and experiences, followed by an assessment of trends and expected future changes in operating conditions and requirements. From this framework, the report proposes improvements to familiar methods and new solutions to eliminate existing shortfalls. It concludes by listing development project opportunities comprising a roadmap for developing new P&C designs for these networks.

2. BASIC PRINCIPLES

LV network systems have been used since the 1920s to provide a reliable electrical power source to densely populated commercial areas, such as office buildings in urban centers. LV is classified as 600 V or less. Typical three-phase LVs are 208 Y/120 V, 480 Y/277 V, and 600 Y/347 V. The LV networks, covering a compact physical distribution area, are supplied by multiple redundant transformers typically from 4.16 kV to 35 kV (usually 12 kV) MV distribution feeders.

The network transformers are contained within vaults—fire retardant enclosures normally within or adjacent to buildings or underneath streets and alleys. They usually contain two or more power transformers, but one-transformer vaults are also common. These transformers are supplied from separate redundant sub-transmission or distribution circuits for redundant supply to the network. They are paralleled on their LV side through circuit interrupting devices called “network protectors” (NPs). Typically, MV current-interrupting devices on the source side of transformers have not been included within the network vault. MV fault interrupting capability is provided by the breaker at the feeder source substation. The LV bus of a network vault may be electrically tied to several other vaults to form a network secondary distribution system, which is the LV network grid discussed in this report. Alternatively, each vault may stand alone as an LV supply to a spot network.

Equipment protection within network vaults is limited, as we explain below. Historically, users have depended upon the physical design of the vault to limit the risks of faults within the vaults. They have relied upon supply substation detection and interruption for transformer faults. LV transformer fuse links and LV cable fault current limiters are common means of LV bus fault protection.

2.1. Network Configurations

Figure 2-1 illustrates a typical LV mesh network system. While the figure shows each network transformer with a supply-side disconnect and grounding switch, many network systems are installed without network transformer high-side switches. The primary distribution substation bus may have several bus tie or sectionalizing breakers to help ensure that one or more feeders will energize the network for the full range of normal substation and network transformer failure or maintenance scenarios. The bus-tie breakers at the supply substations are normally closed but may be opened when there is an adequate source to each bus section to avoid voltage differences between bus sections. A difference in bus voltage magnitude or angle may result in some feeders losing load or carrying the load in the reverse direction, which causes NPs to open, as explained below.

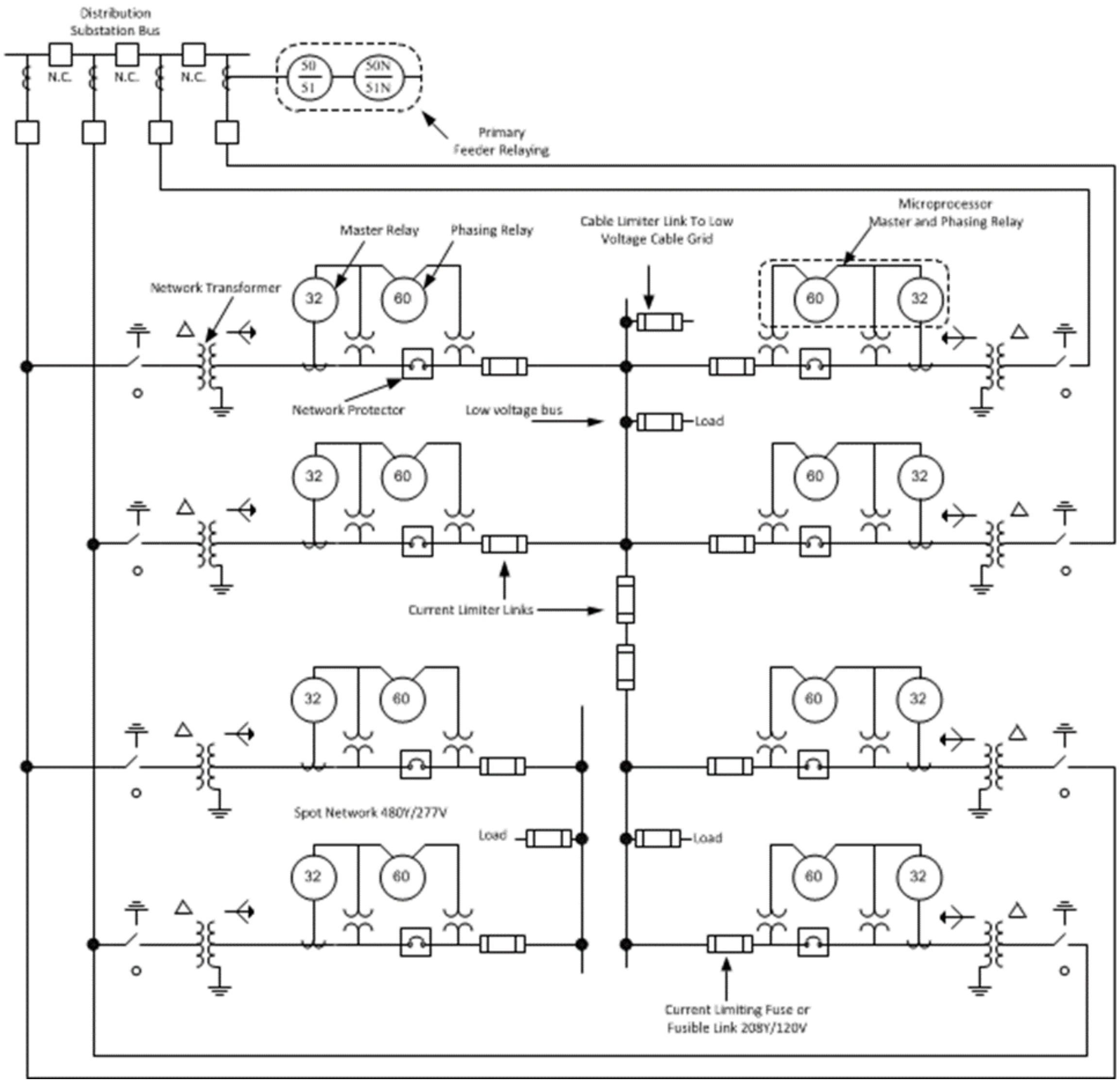

Figure 2-1. Typical LV Network (from IEEE C37.108-2002) [1]

LV faults within network vaults do not pick up substation relays reliably. With earlier 120/208 V networks and vaults outside of buildings, rare faults in the vault were allowed to burn clear. With the migration of vaults into or under buildings and with industry transition to 480/277 V networks, faults are liable to produce smoke and fire risk making it necessary for overt protection of LV faults.

2.2. MV Feeder Fault Protection

In legacy installations, the substation bus is the only source, and the feeder is protected by instantaneous (50/50 N) or time-overcurrent (51/51 N) non-directional overcurrent relays. When the feeder is tripped at the substation, other feeders continue to supply the LV network and supply fault current via reverse flow through the vault transformer. A network protector relay comprises a power directional relay (32) which senses the reverse flow and opens the network protector to remove this fault current backfeed. Note the sequential operation—the substation breaker opens before the network protector.

The amount of fault current backfeed depends on the fault type and transformer winding connection. For a delta primary, the ground-fault current is limited to that from the capacitive coupling. For a wye primary and a ground fault, much more current may flow from the network back to the fault, and fast (under 4 ms) current-limiting fuses or links (see Figure 2-1) may open to isolate the network from the faulted supply.

The protection sequence is the same for the primary switch, electrical connections, and primary side of the transformer, all contained within the vault. However, even with fast clearing, such faults typically damage the vault and enclosed components. A driver for investigations suggested in later chapters is whether faster protection methods can save vaults or increase public safety with a likelihood percentage that justifies the faster methods.

Fault causes within vaults can result from water entry, oil loss, or operator error (opening a switch under load or grounding a live source). Mitigating such events also deserves consideration.

2.3. Transformer Fault Protection

Substation relays should clear faults in the transformer primary winding, but more slowly than feeder or primary connection faults. Secondary LV winding faults are rare and should be cleared by the network protector. If the network protector does not clear the fault, it will burn until the primary becomes faulted and/or until the LV network fuses or fusible links melt and disconnect the network fault current source.

Serious transformer damage is unavoidable for any such fault. Additionally, long clearing times exacerbate vault damage, explosion, fire, and smoke risks.

2.4. Network Protector Faults

Faults on the LV network side of the current transformer feeding the directional master relay 32 will not be detected by that relay and will burn until sources from both sides are removed. Fuse links to the LV network may open after considerable time, but the substation feeder relays are not likely to see the fault until it evolves to include primary winding or conductors. By this time, the serious damage may manifest itself as the above-mentioned explosion, fire, smoke, and public safety risks.

These images of burning faults inside the vault, slowly cleared or uncleared for extended times, point to an interest in other methods of detecting and acting on fault arcing within the vault.

2.5. LV Network Protection

Fusible links will melt for LV faults outside the vault, although they may take seconds or minutes to do so depending on sustained fault current magnitude. Current-limiting fuses are faster but at a higher cost. For 120/208 V networks, arcing faults may produce inadequate fault current and may passively burn clear. 480/277 V network faults do not self-clear. For connections among vaults over a significant physical area, faults may be isolated by fused connections among network segments, along with parallel and separately fused redundant interconnection cables. Coordination of network fuses with those in network vaults can be difficult or impractical in some cases. Overall, protection from LV arcing faults based only on current magnitude may be slow, ineffective, or unselective.

2.6. Ideal Scheme in Annex B of IEEE C37.108-2002

The latest official version of IEEE C37.108, Guide for Protection of Secondary Network Systems, is from 2002 (reaffirmed 2007). However, the IEEE PES Power System Relaying and Control (PSRC) Committee has been developing a new draft. The author of this report reviewed draft 2.18 from February 2019, which forms the basis for many observations in this and the following chapters.

In both versions, Annex B illustrates a complete protection scheme that has not been modified in recent drafts, as shown in Figure 2-2.

Protection functions in this scheme are listed in Table 2-1. The standard shows coordination plots for the MV feed side and the LV network side of the transformers. The coordination does not benefit from improvements that might be achieved with transformer or feeder differential protection (probably for cost reasons), even though these are recognized as possible new applications elsewhere in the latest C37.108 document.

The upper pair of circuit breakers are those at the utility supply substation, with definite-time and inverse-time overcurrent protection functions. This particular deluxe scheme benefits from two MV breakers—the lower breakers inside the network vault at the load site—that can disconnect each feeder from its network transformer. The associated text specifically describes a commercially available vacuum interrupter mechanism cast in epoxy with a small floor footprint next to the transformer. It can execute closing or tripping operations with a 2-cycle fault clearing time.

Also, note the inclusion of electronic fuses of the current-limiting type in each phase of the transformer primary. In some of the application descriptions elsewhere, these are conventional silver-sand current-limiting fuses. High-current faults are interrupted in as little as ¼ power cycle, minimizing fault damage. If the vacuum breaker also trips for the same fault, the unfaulted phase(s) are cleared to avoid steady-state single-phasing or inductive or capacitive backfeeding of the faulted phase from the energized sound phases. This rapid and sequenced clearing is a valuable tool to minimize damage and arc-flash or fire risk in existing and new installations.

To protect against arcing LV faults in vault equipment not sensed or cleared electrically, the scheme relies on heat sensors in vulnerable locations, including the network protector mechanism, transformer enclosure, and LV bus.

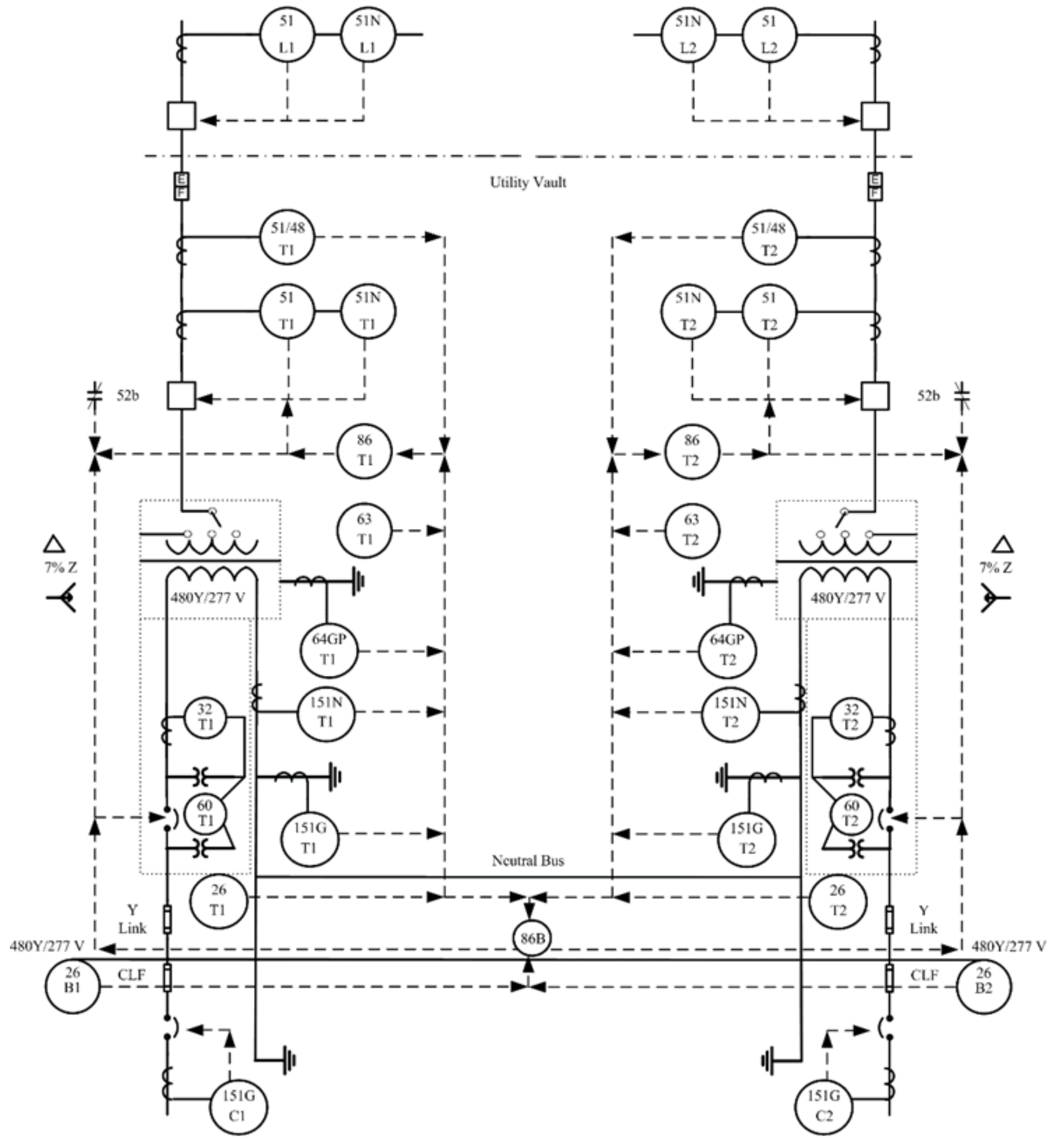

Figure 2-2. Example of Network Transformer Vault Protection Scheme from IEEE C37.108-2002 [1]

Table 2-1. Protection Functions in Network Supply Scheme of Figure 2-2

Device Number with Location in Figure 2-2	Function (location)
51-L1, L4	Time-overcurrent (line)
51N—L1, L4	Neutral time-overcurrent (line)
51-T1, T4	Time-overcurrent (transformer)
51N-T1, T4	Neutral time-overcurrent (transformer)
51/46-T1, T4	Open phase following high current (transformer)
86-T1, T4	Lockout relay (transformer)
63-T1, T4	Sudden gas pressure (transformer)
64GP-T1, T4	Case ground fault
151G-T1, T4	LV ground time-overcurrent (transformer)
151N-T1, T4	LV neutral time-overcurrent (transformer)
26-T1, T4	Heat detector (transformer)
32-T1, T4	Master (reverse power) (transformer network protector)
60-T1, T4	Phasing (voltage balance) (transformer network protector)
151G-C1, C2	Ground time-overcurrent (consumer)
E-F	Electronic fuse (transformer)
Y-link	LV fusible link (transformer)
CLF	LV current-limiting fuse (consumer)
26-B	Heat detector (bus)
86-B	Lockout relay (bus)

3. LITERATURE REVIEW AND UTILITY FEEDBACK

3.1. Documents Reviewed

1. IEEE Standard C37.108-2002 (reaffirmed 2007), IEEE PES Power System Relaying and Control Committee (PSRC) – *Guide for Protection of Secondary Network Systems*. [1]

   The report author, a PSRC member, has access to the revision project document PC37.108 draft 2.18, November 2019, and relied largely on the draft revision in this review of practices. Improvements in the new draft are incremental. This study shows that old visions of new opportunities have not yet been updated to reflect the likely direction for these ideas, as noted especially in Annex C. (Some ideas in this report might suit that annex.)

2. IEEE Standard C57.12.44-2014, IEEE Standard Requirements for Secondary NPs. [2]

   The standard presents complete details of design practices, design requirements, and conformance type tests for each component of the LV network protector and its enclosure. It includes substantial details on application and issues for protection components, including network relays, operating characteristics, fuses, overall protection zones and philosophies, and industry application issues. Protection advice in C57.12.44 is not fully aligned with that of C37.108. C57.12.44 presents more on settings issues and relay behavior. It becomes clear that microprocessor relays can correct many sensitivity issues.

   The standard points out the need to avoid misoperations on transient reverse flows. Descending construction elevators are an interesting new source of backfeed to the utility, along with DER on the LV network. Other reviewed documents show that some new network relays (notably ETI MNPR) offer characteristics with a tolerance of transient limited backflow.

   The standard clarifies that a network protector was never intended to stand open between two unsynchronized sources. All network feeds must come from a common equivalent source, typically from one substation. This imposes limitations or protection needs to handle some future situations.

3. IEEE Standard 241-1990, IEEE Recommended Practice for Electric Power Systems in Commercial Buildings (IEEE Gray Book). [3]

   Chapter 9 gives detailed protection design and application recommendations for all aspects of commercial building installations and equipment, including extensive treatment of fault calculations and coordination procedures. This highly detailed and broad standard is observed on a high level to align with the LV network-specific advice of the prior two references.

4. Ferris, H.J and Richards, E.F., *Protection of 480 Volt Network Systems*. Ferris Engineering, St. Louis; and University of Missouri - Rolla. [4]

   A technical paper presenting a review of standard LV network applications obtained as printed copy only (no online version found), and the document's era appears to be 1990-2000. The paper focuses on uncleared or slowly cleared faults with calculations of what materials are damaged to what extent as a function of fault current and duration. To mitigate damage and fire risk, the paper presents schemes and coordination for LV network arcing ground faults to achieve the fastest trip times, including using a zero-sequence differential scheme.

5. Shields, Francis J., *The Problem of Arcing Faults in LV Power Distribution Systems* (GE), IEEE Transactions on Industry and General Applications, Volume IGA-3, No. 1, January-February 1967. [5]

   This paper gives an extensive explanation of relaying methods and shortfalls for arcing LV ground faults. Then it presents the benefits of using ground-sensor relays (GSRs) (GE doughnut residual CTs) at network protector terminals and other ground measurement points to improve speed and coverage. It discloses cases still not covered even with GSR.

6. Kojovic, L. A., and Bishop, M.T., *New Spot Network Protection Concepts* (Cooper Power Systems, now Eaton Electrical).

   The author of this report located a paper copy (as submitted for a protective relay conference), and it is estimated to be from 2005. It reviews standard grid and spot network concepts. Then it proceeds to present two new protection zone schemes in which compact Rogowski coils are used to configure differential protection zones surrounding transformers, protectors, and LV buses. Several differential zone deployment proposals in the present report are aligned with this work.

7. Baier, M., and Smith, D.R., *Connection of a Distributed Resource to 2-Transformer Spot Network* (Eaton Electrical), IEEE T&D Conference, 2003. [6]

   The paper presents the application scenario of a 75 kVA induction generator on an LV network with two 1 MVA transformers and describes fault studies and impacts. It presents a control scheme that detects dropping load infeed to LV networks and trips the DER generator to avoid backfeed until load returns to a safe level. The scheme is implemented with Eaton MPCV relays and added control logic.

8. M. Behnke, W. Erdman, S. Horgan, D. Dawson, W. Feero, F. Soudi, D. Smith, C. Whitaker, B. Kroposki, *Secondary Network Distribution Systems Background and Issues Related to the Interconnection of Distributed Resources*, National Renewable Energy Laboratory TP-560-38079, July 2005. [7]

   This National Renewable Energy Laboratory (NREL) 2005 workshop report gives succinctly reviews LV network applications. The workshop discussion comprehensively lists issues but presents no solutions. Topics include:

   - Variety of network configurations in service—grid, spot, radial and loop, primary and secondary transfer
   - Size, type, number of network units, and voltages
   - Network protector operation and settings
   - Coordination (settings and communications)
   - Automation
   - Maintenance
   - Network protector unwanted/undesired/spurious tripping
   - Reverse power issues
   - Normal and fault operating conditions and responses
   - Cycling or pumping

- Closing supervision—PG&E solution or Con Edison detector unit for DER >50% of network protector online requirement (in alignment with IEEE 1547)
- DER design and operation
- Islanding
- Security

9. Coddington, Kroposki, Basso, Lynn, Sammon, Vaziri, Yohn, Photovoltaic Systems Interconnected onto Secondary Network Distribution Systems – Success Stories, NREL TP-550-45061, April 2009. [8]

   This NREL report gives a tutorial on LV network design variations and issues. It presents case studies where DER inside facilities did not cause export issues with NPs. It describes a series of design and operating requirements such that DER inside a facility does not cause export issues with NPs or changes in their protective or service reliability features. It gives design examples of how to meet these rules with DER installations for service reliability and safety. No export of surplus DER production is foreseen in this work. It also does not treat islanding or microgrid operation.

10. IEEE P1547.6-2011, IEEE Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks. [9]

    This standard extensively describes LV network applications, as they relate to requirements of parent IEEE Standard 1547 for connection of DER to distribution systems. It states requirements for NPs with downstream DER:

    - Should not cause any NP to exceed its fault-interrupting capability
    - Should not cause any NP to separate two dynamic sources
    - Should not cause any NP to connect two dynamic systems

    It gives requirements for P&C:

    - Should not cause any NP to operate more frequently than before DR operation
    - Should not prevent or delay the NP from opening for faults on the network feeders
    - Should not delay or prevent NP closure
    - Should not energize a de-energized network
    - Should not require the NP settings to be adjusted except by consent of the area EPS operator
    - Should not cause an islanding condition within part of a grid network
    - Should not remain connected to the network if 50% or more of the NPs serving the network are open

    After reviewing studies of the impact of DER on circuit operation, the report gives guidance for connection of DER:

    - Multiple specific examples of *de minimus* application limits ensure that DER has no adverse impact on LV system operation per the above requirements lists, even under extreme expected excursions of low energy demand in the facility.

- Transient small backflows may be acceptable to some utilities in recognition of situations like elevator backfeed.
- Gives examples of active control schemes that either disconnect DER when it becomes excessive compared to load or issues control commands to throttle back controllable DER inverters to remain with operating criteria.

11. Eaton Electrical, *Spot Network Application Guide*, web literature [10]

    Relevant content is in Tab 18 with detailed product and application guidance for LV networks and components—oil-filled and dry transformers, CM-52 NPs and enclosures, fuses, MPCV relays and older relays, disconnect switches, and bus interconnections. It includes detailed application documentation for MPCV network relays, with operating scenarios and characteristics. Related Eaton web literature is MPCV Instruction Booklet IB02402001E with installation and communications details (2010 edition posted).

12. ETI (Richards) Manufacturing, ETI 521125 *Fieldpro MNPR® Interface Software Instruction Manual*, Revision 19, 2015. [11]

    This manual focuses mainly on software guidance for communications with the ETI MNPR network relay. It appends operating characteristics and settings for MNPR, suggesting functionality details but without detailed treatment. Further web search yielded an overall ETI NP design brochure but no detailed application guidance.

13. Feero, W.A., Generation Monitoring at the GSA Williams Building and Modeling of Feeder Fault Cases Recorded, Report to Massachusetts Technology Collaborative Renewable Energy Trust, 2005. [12]

    The report describes an experimental high-speed measurement installation sampling LV network voltage, currents in two NPs, and load generated from each PV array and induction DER. Results show dynamic behavior for load and generation variations and faults. The report recommends PSCAD simulations for determining DER application limits. If generation can exceed the reverse power tolerance settings of network relays, many faults on the outside distribution system can cause those relays to trip undesirably. PV with a rating of less than 30% of minimum facility load has a low risk of such misoperation. It is not stated but easy to conclude that the load can be monitored in real-time to achieve the same security. The report recommends that if any network relay trips, DER should be tripped at the same time.

14. M. van Herel, W. Heffernan, A. Wood, Managing fuse protection in LV networks with distributed generation, Canterbury Univ., New Zealand, 2019. [13]

    This paper was included in the initially proposed review listing but was found to apply to distribution systems, not LV networks. To avoid fuse or protection misoperations for external faults, pickup must be greater than 1.2 times the maximum DER rating. To ensure adequate protection, pickup must be less than the feeder rating minus 1.2 times the maximum DER rating.

15. Ogden & Yang, Impacts of Distributed Generation on LV Distribution Network Protection, Aston Univ., UK 2015. [14]

    This paper was included in the initially proposed review listing but was found to apply to distribution systems, not LV networks. It covers graduate research focused on typical distribution systems with DER rather than high-density LV networks. Problems studied include fault current duty variations, protection coordination, blinding of protection by DER fault current, islanding, and reclosing failures. The paper gave no specific solutions but suggested that adaptive protection schemes should be studied.

3.2. Notes from Discussions with PHI PEPCO

Telecon with PHI network engineer Stephen Steffel, June 4, 2020:

1. Stephen described IEEE 1547 problems with a slower-than-specified shutdown of inverters for PV on LV networks – greater than 2 seconds – this causes occasional false network protector relay trips. This is rare but PEPCO has experienced some scenarios.
2. PHI uses Eaton VaultGuard network protectors. Reverse power protection is required on any connected DER over 50 kW, plus telemetry for systems 150 kW and above. There have been problems where developers have used generator run-back schemes (PV output reduction schemes) to protect against the situation where reverse power could occur – if a load instantaneously shuts off and the load of the facility is then lower than the generation. This was addressed by having a safety margin that would normally handle load fluctuations. If based on the monitoring (as included with generation installations of 150 kW and over), and if the reduction scheme can be shown to be fast enough to prevent the NP relay from tripping, the installation may be eventually be considered to operate without a safety buffer or a smaller one.
3. The other reason for requiring telemetry for systems 150 kW and above is because of difficulty diagnosing event-related problems with data from customer-owned systems. PHI had tried calling for customer system data in the beginning, but the historical data capture from customers was not adequate for identifying the problems causing inadvertent trips of network protectors.
4. ETI Richards is providing new relay behaviors to help Con Edison solve slow inverter problems (Con Edison interviewed separately). The new behavior is using adaptive trip with rate-of-change-of-current permissive supervision for grid networks.
5. PEPCO is using AMI infrastructure for monitoring of vaults. This includes Itron Silver Springs Networks Gen 5 radios, capable of response in a few seconds after an event or trigger.
6. Monitoring includes water level, temperature, and electrical parameters.
7. Monitoring covers maybe 15% of vaults – a remote monitoring system (RMS) is costly.
8. PHI would like to have lower-cost, reliable, secure communications between DER and network or protective relays.
9. PHI wants RMS built out to full coverage before considering any allowance of reverse power flow from the LV network into the distribution system. They can monitor loading. They want to see DER output less than 80% of the minimum daytime load on the network connection or have a safety buffer of 20% before reverse power operation occurs on the network protector(s).
10. PHI is looking at the coming challenges of EV charging on LV networks – how to shed charging loads, and car-charger communications.
11. ConEdison and PSE&G are working on lower-cost communications – Stephen recommended talking to them. ConEdison has 27,000 transformers, typically 2.5 MVA. [*See ConEd interview notes for more details on their LV network infrastructure and issues.*]

12. PHI has posted a condensed version of its 70-page Technical Interconnection Requirements at https://www.pepco.com/SmartEnergy/GreenPowerConnection/Documents/TIR%20Summary%20as%20of%201-12-2021.pdf.

3.3. Notes from Discussions with Oncor Energy Delivery

The project investigator conducted an Interview with Mark Carpenter, Vice President, an acknowledged industry system protection expert who rose from System Protection ranks. Mark described recent Oncor initiatives to review its LV Network protection design standards for safety and effectiveness.

1. Oncor emphasized that the LV network protection standards cited in the following have been immediately focused on new installations. A retrofit program based on revised standards is to be conducted over many years.
2. Oncor reviewed, updated, vetted, and benchmarked standards for LV network design and protection for facilities in Dallas and Fort Worth, TX, in early 2017. The review documentation includes a long list of specific technical recommendations with rationale for each, reflecting careful thought and evaluating every scheme and fault scenario.
3. MV switchgear protection standards for network service are under revision in 2020.
4. They traveled to and interviewed several utilities with extensive LV networks, including Con Edison.
5. Their philosophy includes many layers of protection to avoid uncleared arcing faults. Different schemes handle different situations so that all plausible cases are covered.
6. Oncor supplied design standards. These reflect the complete protection application philosophy, which does not spare CTs, relays, or breakers to handle fault cases that many industry-standard designs relegate to backup or sequential protection.

Key specific observations in the revised Oncor standards are as follows:

1. MV supply designs are different in Dallas (wye-G to wye-G) versus Ft. Worth (delta to Wye-G) which impacts protection design for some fault cases.
2. All schemes are specified to work for N-2 failure contingencies. Backup protection schemes are included for all cases where tripping or fuse/link clearing is specified.
3. All legacy electromechanical (EM) protection schemes are to be upgraded as targeted to new microprocessor relays.
4. Relays and trip circuits are powered from two sources, or at least one source not impacted by any fault. Capacitor trip energy storage is specified for some cases where no storage was previously required.
5. SCADA is to be installed in every vault.
6. Preferred network relay is ETI type MNPR.
7. In operation, network relays are validated from the control center by a dropout test detailed as follows:
    a. Trip the MV supply feeder and observe network relay opening of protector.
    b. Restore MV supply and manually close protector
        i. This requires high sensitivity of the network relay to reverse flow.
        ii. It must trip even for transformer magnetizing current from secondary energization.

8. Not obviously observed by Oncor:
    a. The above scheme would be at odds with outfeed from DER unless the relay can look at the phasor relationships of currents and voltages to distinguish feeder loss from local generation outflow - some relays might do this for them
    b. Integrating NPs with SCADA can provide an alternative means of validating the availability of protection.
9. DER applications are foreseen, but no schemes are yet specified. The new 2020 MV protection document shows a case of a customer with DER and the protection scheme to accommodate.
10. Breaker failure protection with backup tripping is specified for MV switchgear. The maximum clearing times of primary protection by relays is 15 cycles (0.25s).
11. Protection failure for 480 V or 208V NPs is provided by the NP fuses.
12. Relays are applied for 480 V buses. 120/208 V bus faults are expected to burn clear or be cleared by cable current limiters. The report includes extensive restudy of this long-standing topic to provide strong justification for this core concept that voltages below 231 Vac cannot sustain an arc in the operation of 120/208 V mesh distribution networks.
13. Heat detectors are installed in NPs and other specific locations. For MV supply side, bus, and transformer, certain legacy heat detection devices (Newer schemes show Protectowire sensors and control.)
14. LV bus protection uses an SEL-751 customer supply overcurrent relay with trip supervision by optical fiber sensing for arc flash detection. The fibers are easy to install and robust. Fiber sensing of fault events has been completely reliable in extensive testing and takes less than 5 ms. This layer of protection is in addition to supervised instantaneous trip functions in NP relays. For customer-side faults, the customer fuse interrupts.

    Other types of optical sensing devices used in the past were prone to misoperation from accidental exposure to normal light sources or daylight.
15. For 4 kV and above spot network switchgear, transformers are protected by SEL-787 microprocessor current differential relays for high sensitivity, with backup protection for LV side feed to a fault with SEL-751 directional overcurrent relay looking from secondary back to transformer and MV source. The SEL-787 has current-limiting detection, which avoids tripping the low-side current infeed to a fault exceeds the current interrupting capability of the high-side switch (legacy Powell or new G&W vacuum interrupters).

3.4. Notes from Discussion with Consolidated Edison Company of New York

The Quanta Technology team, including Sandia National Labs (SNL) project leaders, conducted four discussions with Christopher Jones, Con Edison Chief Electrical Engineer for Distribution, the last of which took place on November 10, 2020. Participants included Christopher Jones and his team members Sergio Rodriguez and James Leary, plus Matt Reno and Mike Ropp of SNL; and Eric Udren, J.C. Lesieur, and Mike Longrie of Quanta Technology.

1. Con Edison has 2/3 to 3/4 of the LV mesh network infrastructure in North America with 28,000 network transformers and protectors.
    a. Typical spot network has between 2 and 6 transformers with an average of 3. This is completely different from other distribution networks.
    b. ConEd has a history of creating new methods and approaches for spot network applications.

c. ConEd replaces over 800 transformer/protector installations a year, which is more than what most utilities have in total.
d. They experience about 3,000 events per year, including low levels. The majority are low-level 'smokers' and explosions are rare.
e. Con Edison participates in EPRI North American Distribution Utility Working Group (NADUWG). EPRI contact is John Tripolitis.

2. Major challenge #1 - to reduce utility hole fires and explosions.
   a. 'Smoker' is reported by the public – cable breakdown will build up heat, goes to LV fault.
   b. Most of the 3000 LV faults each year slowly sizzle and cook. There may be 60 to 70 fires per year, and less than 20 explosions.
   c. Sensors in structures might give us a few hours of advance warning – this possibility is still being explored and not yet confirmed.
   d. At 460 V, NPs melt down potentially generating smoke, CO, and other gases . Emergency crews lift covers first to make them safe to enter.
   e. There are more of these smoking events at 120 V than at 460 V – the latter has isolation switches with fuses.
   f. There is a 'Citizen App' to alert the public and the fire department, but the level of use is not known.
   g. Monitor for alarm triggering or protection – smoking utility hole, AMI, and structural observation system (SOS) signatures (next) are under continuing development.
   h. SOS is a Con Edison assembly of vault observation equipment deployed in a couple of thousand locations. It includes detection of CO, flammable gases such as methane, stray voltage from neutral to cover. It additionally includes an infrared (IR) secondary system imaging. Reports are generated every 6 hours.
   i. Dynamics of explosions – ventilated covers on 85% of manhole covers and 50% of service boxes let gases escape.
   j. Latched covers don't fly into the air as unlatched covers can do.
   k. EPRI has tested for explosions – Lennox, MA lab.
   l. London, UK, has piloted the filling of service compartment with sand, but this was difficult to work with.
   m. Con Edison has tried filling vaults with bags of pearlite ("pillows") – okay for small spaces but impractical in a large utility hole.
   n. AMI detects flicker, but it is logistically challenging to gather this evidence. ConEd is working on triggering locally for flicker criteria and raising a binary alarm – a lot of data has been gathered.
   o. 3-phase KV2C meter is a PQ device that can detect flicker from floating or disconnected neutral or bad customer ground and reporting by AMI – a success story. I-210 (GE) single-phase residential meter has some indications of voltage problems but is less reliable for flicker or fault diagnosis.
   p. Mike Longrie – AMI with Silver Springs/Itron gateway can handle some local filtering of detection data.
   q. For bad neutral and bad customer ground in tandem, the phase to neutral voltage goes to half the phase-to-phase value – a reliable indicator of trouble.

r. More voltage measurements with more or more compact PTs could provide monitoring opportunities (see (8.) below).
s. Infrared arc detection is interesting, with other logic incorporated as in SOS.
t. An interesting study topic – what sort of local customer-site processing could turn available data and evidence into a binary trouble alarm to communicate?
u. Strong evaluation criterion – dependability versus security. Even if the solution only partially indicates problems, we might benefit. However, we cannot use any detection solution that gives a significant level of false alarms – it is not practical to chase them all, and confidence in the solution is undermined.

3. Major challenge #2 - to reduce stray voltage hazards.
   a. Hazard is contact voltage rise on utility hole covers, streetlights or traffic light poles, or customer facility surfaces.
   b. Publicly visible and emotionally charged issue – 2004 case of a person killed by contact with an energized utility hole cover.
   c. Can be an insulation breakdown, installation failure, or caused by voltage induced from stray neutral current if the intended neutral path opens.
   d. Con Edison scans the system with a power survey—Sarnoff Vehicle—a truck-mounted E-field sensing system to spot potential problems for more focused measurements. This cannot be used near overhead circuits.
   e. NY State (& RI State) criterion is that over 1 V potential with a 500-ohm load is a hazard that must be repaired at once when found or guarded until repair.
   f. This alarm level is impractically low – not a hazard to personnel and may arise naturally when there is no failure or hazard. Requires difficult mitigations of issues like normal neutral voltage drops, when crews should spend their time addressing real personnel hazards. The only documented issue is that cows subjected to this voltage may produce less milk.
   g. A better level, used in some other jurisdictions, is 3 to 5 V with a 15k ohm burden. This characterizes insulation or neutral failures that should be checked for a legitimately hazardous situation.
   h. This detection and mitigation issue is troubling to Con Edison – new aids and solutions could be useful.
   i. IEEE papers have suggested a methodology of measuring harmonic voltages. In normal load situations, the neutral voltage comprises significant harmonic content. With abnormal load flow in the neutral path, there is a larger than normal fundamental power frequency content. ConEd is interested in learning about the usefulness of this neutral voltage measurement analysis.
4. Discussion of network protector (NP or NWP) operations and pumping (any undesired and repeated opening and closing of protector).
   a. Scenario is trip on reverse flow followed by reclosing attempt and retrip; random opening and closing on low load followed by acceptable voltage match conditions for closing.
   b. Con Edison wants to enable automatic reclosing of the protector, so installation does not wind up operating with only one feed and human intervention. Site visits to reclose protectors are minimized with autonomous operation.
   c. Con Edison has practical maintenance and operating procedures in which the network relay is set to '*Insensitive*' (to reverse load flow) to avoid unwanted operations. An adaptive tolerance scheme would be better.

   d. To stop pumping operations – change to a desensitized state of 2-state relay load sensing algorithm.
   e. For the random opening on low load levels, Con Edison waits 38 hours and then allows closing if voltage magnitude and phase differences meet basic safe closing criteria – and *not* requiring network side to be 1.4 volts below supply side as might be implemented in some relay logic.
   f. For critical customers with spot networks, use manual control by communications when applying basic safe closing criteria.
   g. Con Edison has developed other logic and manual procedures aimed at minimizing truck rolls.
   h. If the feeder goes out of service and we can see LV network voltage, Con Edison can use feeder voltage loss to close the protector so service can be remotely restored.
   i. Some of these schemes and settings are new – there is a journey over time to roll them out across the system, as Con Edison prioritizes deployments.
   j. A suggested study topic is to collect a complete set of use cases or application scenarios and document holistic logic solutions and implementations to achieve all Con Edison and industry objectives for reliable service and minimized extra site visit and maintenance activities.
   k. There is a settings or configuration management challenge – they may lose track of records of settings in particular locations. Configuration management is a separate industry initiative topic for P&C in general, which Con Edison is addressing broadly.
5. Climate change concerns – stormwater incursion.
   a. Some vaults with water incursion have sump pumps – not determined if failure is monitored.
   b. Con Edison would like to monitor submersible vaults with pressure for water leak avoidance.
   c. ConEd is also making more network protectors submersible.
   d. ConEd is developing submersible dry-type transformers.
6. Transformer failures are down to 10% of what they were just 15 years ago.
   a. Tank degradation is a source of failure. Con Edison monitors tank pressure, temperature, and oil level in the majority of cases.
   b. Con Edison monitors the pressure of oil-filled or dry-type transformers – 3 psi maintained to detect leaks in service. Use 8 psi for 1 hour to test for leaks on site. Pressure monitoring has been a key success factor.
   c. Con Edison correlates temperature and pressure co-variation to detect problems in advance and reduce in-service failures. Comparison is done in back-office monitoring systems, not on-site.
7. Compact voltage measurement solutions.
   a. Con Edison has been investigating compact fiber optic MV PTs. Performance is still under evaluation.
   b. High-impedance resistive divider PTs are still an option.
   c. Solution needs to be suitable for dc hi-pot testing with phase to neutral connection.
   d. Adapting these PTs to transformers.
   e. Undervoltage and overvoltage protection are important.

f. A fiber optic PT can safely measure phase-to-ground voltages for ungrounded feeders – this gives new visibility of voltage behavior and problems previously unknown.
g. For insulation failures or faults, the phase to ground voltage rises to the phase-to-phase value on the other two phases, even higher with the capacitance of the cable. Sometimes shunt reactors are needed.
h. When PV or DER has high real power output, the voltage can go too high.
i. An inverter can manage this with reactive power delivery capability and control.

8. Communications for monitoring
    a. Most widely used communications are power-line carrier (PLC)-based collection at low data and polling rate for analog values plus binaries for power direction, protector operation any time in the last hour, transformer tank pressure switch or analog, temperature switch or analog.
    b. Looked at and tried AMI gateway (access point or AP) data gathering, but it is not cost-competitive.
    c. Transitioning to cellular access – small modem installs in a vault with two service cards (using Verizon now). About 3000 locations; 200 new installations per year in the capital program.
    d. Basic Schweitzer Engineering Labs (SEL) real-time automation controller (RTAC) integrates Richards relay communications and performs on-site logic and processing.
    e. For networks or loads with DER – if Con Edison trips feeder and wants to trip DER, control center verification takes 10-20 s. They do not require anti-islanding but don't want customers to be energized by DER.
    f. More back-office data analytics might support trend diagnosis, event analysis, and asset management objectives, including tracking the integrity of network transformers.
    g. Area of study – cathodic protection of transformer tanks against corrosion. Sometimes the anode has disintegrated. Can we measure current or use some other means of alarming if corrosion protection is not working? SOS can take pictures.
9. Fault location, isolation, and service restoration (FLISR)
    a. Con Edison is beginning with trials of new, more capable relays and MV interrupter switches with FLISR to improve feeder reliability and reduce risk.
    b. FLISR is implemented with communications and "grid-edge intelligence" in peer-to-peer or centralized schemes to remove the operator from the restoration sequence.
    c. ConEd is evolving the strategy for FLISR, looking at IEEE 2030.5 and investigating what tools are available to put in an implementation roadmap. Working on how to fit industry strategies to network service constraints.
    d. Determining what is suitable cybersecurity for peer-to-peer and hub-and-spoke FLISR schemes.
    e. Con Edison liked the idea of a standardized integrated P&C package – thought this can be a good solution for construction and commissioning.
    f. Sergio has tried an IEC 61850 scheme for sectionalizing networks on the fly for flooding.
    g. An overall strategy with internal and external information interfaces would be helpful.

10. Advanced distribution monitoring system (ADMS) and DER initiatives
    a. The control center is GE XA-21 – being upgraded shortly.

b. The ADMS strategy is controlled for reliability – DER management system (DERMS) is coming later.
c. Con Edison is presently running its DMS with 300 users. It includes ratings and flicker.
d. Dr. David Wang and a team of 7 developers maintain the DMS app and provide technical support.
e. The system deals with individual devices, looking at how to coordinate among devices and run the system holistically.
f. This depends on a good model of the whole system – not yet developed.
g. Working on basic capabilities – load flow, contingency analysis. Talking to Siemens and Cooper (CYME). Models have 1 M nodes – they want load flow and contingency in under 20 s.
h. Con Edison has regulatory requirements to solve for N-2 contingencies – other utilities may not face this need.
i. DER penetration is advancing quickly, so they are experimenting with approaches – volt/var control, altering characteristics of sensitive reverse protection, adaptive relaying characteristics.
j. Matt Reno: How about integrating AMI with load flow? Sergio: Integrate GIS as well. We have a reconciliation process to find peak demand – AMI will give us some more input, but the process will stay the same as long as they are in experimental development mode. They are already using customer billing (CIS) data in the reconciliation process to figure out valid load levels. ConEd reported subsequently that its revenue meters are used in load flow and they are converting over to the AMI meters to get more accurate peak load data.
k. The goal is to forecast peak demands with upper and lower bounds, including consideration of temperatures, year-to-year variances, and residential and commercial rates of change of loading.

4. OPPORTUNITIES FOR TECHNICAL EXPLORATION

LV network design, operation, and protection have been refined for a century with practices that yield high service reliability, so it is challenging to propose major leaps in core performance. Nonetheless, there are five areas of recent technological advancement that drive opportunities for new concepts. These five areas are:

1. Increasing demands for fault energy and arc flash reduction, along with reduced tolerance for rare but threatening uncleared faults and resulting burndown events
2. Introducing DER in customer and utility portions of the distribution grid, which can alter legacy unidirectional power flow assumptions
3. Advancing the measurement and logic capabilities of microprocessor-based relays
4. Evolving communications technology to support fault protection, monitoring, and control for new operational demands
5. Evolving concepts of P&C system integration and monitoring to assure continuous operation while reducing maintenance testing

Combining awareness of these elements with a literature evaluation and industry discussion triggers research and development proposals.

The concepts presented in this chapter are filtered lightly with considerations of practicality and economics. The actual cost, and the business case drivers that would justify the investment, would be evaluated as a specific design or implementation is defined in higher detail and vetted by a range of industry experts.

The following subsections show interrelationships of technical developments that can be integrated to yield improvements in protection and operation. These relationships point to a holistic parallel advancement program in multiple listed areas.

4.1. Improvements to Vault, Network, and Protector Designs

Optimization of the design of existing components can be carried out in conjunction with the results of a workshop among identified manufacturers, utility engineers, and construction and maintenance personnel. Service, performance, and failure issues or cost improvements can be directed by industry experience, including example issues from NP, network fault protection, and commercial distribution application references in Section 3.

This report has not prioritized specific equipment or hardware issues or optimizations, many of which are listed as causes of potential failures and faults in a generally reliable set of designs. However, an optimization workshop should be informed with recommendations from development studies described in the following sections. Three examples are as follows:

1. Section 4.1.2 makes a case for primary transformer current measurements, with CTs or newer compact instrument transformer (IT) technologies embedded in standard designs.
2. More integrated transformer and protector measurement and relaying zones may make a case for secondary CTs on the load terminals rather than on the supply side of the NP contacts.
3. As a supplement or alternative to primary supply breakers, Section 4.1.2 proposes new fault-shunting schemes that would be implemented with mechanisms on the primary side of the transformer.

4.1.1. Issues

1. MV breakers, LV NPs, and similar LV external air circuit breakers are complex spring-loaded mechanisms with bearings and sliding mechanical arrangements that must move in milliseconds to achieve fault current interruption. These mechanisms rarely operate in normal service scenarios. This requires periodic maintenance operations or lubrication.
2. While correcting mechanical issues from a lack of operation, breaker or switch maintenance yields a significant risk that the mechanism has been damaged or left in an unintended assembly state.
3. The mechanical design and the arc interruption mechanisms result in a design that may, over a long period in dirty environments, result in contamination that renders the breaker incapable of interruption. Alternatively, contamination of insulators can lead to faults.
4. The nature of vault installations exposes them to flooding and rodent and insect invasion, which overcomes designed protection against these influences.

4.1.2. Solutions: Limits, Practicality, and Economics

It is presumptuous to suggest that manufacturers with many decades of engineering experience, working with their field engineering and maintenance customers, have not already optimized designs and maintenance procedures to achieve the best possible result. However, it is possible that trends in parallel product design areas have not yet been brought to bear on LV secondary vault and distribution network installations. It is also plausible that manufacturers receive inconsistent feedback on the reliability and maintenance issues of products they have sent to the field. The feedback would comprise mainly real-time failure or problem reports that are difficult to correlate with the variety of installation, service, and maintenance practices.

If there is an opportunity here, it would first be necessary to make the following proposals and sort through the validity of the industry's resistant responses to see if there is a path forward.

1. In the electric utility MV and high voltage (HV) breaker domain, new designs have emerged which specifically achieve low maintenance requirements through new materials and changes to the design of lubricated moving parts and interrupting mechanisms. It may be worth bringing breaker design experts' and users' attention to bear on opportunities for optimized protector and breaker designs that can remain idle for long periods with low risk of problems and require little periodic maintenance.
2. A particular benefit is achieved if the mechanism is designed specifically with monitoring capability—for example, an optical travel sensor whose output would indicate any small irregularity in the movement of breaker or protector mechanisms. A strain-gauge mechanical sensor attached to the mechanism at an acceptable cost can also report a vibration, shock, or sound sequence which aligns with standard behavior or indicates a malfunction.
3. It is feasible to develop trip-monitoring and close-monitoring measurement functions in network relays and/or other installation protective relays, which in a test operation, can determine that a protector or breaker is not performing to specifications. If such operational testing is automated, the need for periodic maintenance may be reduced or eliminated, along with the risk of maintenance work on the mechanism. Maintenance personnel is then charged with responding only to malfunction alarms and occasional physical inspection of vault installations. Section 4.8 presents the operation timing logic.

4. The cost of new lower-maintenance designs may be close to or somewhat higher than that of legacy mechanisms. However, a business case may be built on potential and substantial savings in maintenance costs, along with the economic valuation of avoided incidents of uncleared or slowly cleared faults with damage and risk.
5. Protectors and breakers operationally checked in this way offer superior asset management strategies and may offer longer service life. Foreseeable failures are discovered in routine operations and tracked across a fleet of similar devices. The low failure rate of a fleet indicates no need for new investment. Gradually increasing the rate of problems leads to root-cause analysis and mitigation actions. If a fleet is beginning to suffer some fundamental design or aging issue, upgrading or replacing the entire fleet minimizes the risk of disastrous misoperations, even if the forecast service life has not been achieved.
6. The installation-monitoring and fleet-monitoring strategies would be further improved if vendors implemented an occasional recovery of regularly monitored field service units that would receive a full product type test. This might detect gradual degradation of insulation or loss of high-current interrupting capability, which might always be cited by hesitant experienced personnel as weaknesses in a condition-monitoring approach as described above. This comprises a deep examination of low-probability problems for which attention may not even be justified, as might be discovered if it is tried.
7. An industry initiative or workshop that revisits the basics of component design within the network vault should be armed with prospects from subsequent sections of this chapter—for example, efficient integration of new or additional phase and summation type instrument transformers (ITs) or IT technologies. This also includes a review of neutral connection and grounding facilities looking for any possible LV ground fault sensing improvements.
8. The industry engagement should gather user experience with devices and methods used to power the protection systems and switching devices when the utility supply may be lost in the fault event. This includes capacitors, batteries, or CT-powered electronic and control circuits critical to NPs and scheme performance when facility service has been disconnected.
9. This report observes that the emergence of DER, including all of wind generation, photovoltaic generation, and battery energy storage systems (BESSs), use inverters whose electronic power switching capabilities at LV and MV can be applied to flow control, as well as operational and fault switching of LV networks and their MV supply sources. A fully self-monitored solid-state electronic power control system design offers the flexibility of operating modes and limiting or shutdown of fault currents for faults external to the electronic switching arrangement. The electronic network interface control could directly interface with DER, even providing uninterruptible power supplies or microgrid functionality in conjunction with a local storage battery or small pumped energy storage facility.
10. The reliability of an electronically switched interface as compared to existing EM systems requires evaluation. Some conventional isolation switching, fuse protection, or even circuit breakers and separate relays are still required for safe maintenance and protection against short-circuit faults in the electronic systems. Is the substation protection and breaker adequate for such events?
11. A research topic is to architect an integrated electronic MV-LV network interface configuration with DER integration, including specifications for control, protection, and maintenance capabilities.

4.2. Transformer Protection

In typical applications, MV feeders from distribution substations connect to network transformer primaries, either directly or through manual dead-break-only disconnect switches with grounding capability. The transformer and its connections are thus protected by the substation feeder 50/51 relays.

4.2.1. Issues

1. The fastest clearing is on the order of 5 cycles when the fault current is high—transformer primary-side faults cause significant damage.
    a. Coordinated 51 trip time may take a fraction of a second or multiple seconds, causing far greater damage and risk of fire or explosion.
2. The 50/51 substation relays will only respond for faults part of the way into the primary winding.
3. The remainder of the primary and the secondary winding up to the secondary CT and NP source contacts comprise an unprotected zone for feeder tripping, incompatible with acceptable protective relaying practices today.
4. Operation of the network relay for reverse fault current from the network will not generally disconnect the supply feeder.
5. The uncleared fault will burn until the transformer's primary side circuit becomes faulted and trips the feeder via substation relays.
    a. Even local feeder-side relays and breakers, or fuses, may not clear secondary-side faults.
6. Tripping the feeder de-energizes other transformers and/or LV networks supplied by the same feeder.

4.2.2. Solutions: Limits, Practicality, and Economics

1. The high-side fusing of a transformer is often used—a simple, affordable, space-saving improvement.
    a. High-side fuses remove the transformer fault from the feeder and help with continuity of service to other transformers elsewhere on the feeder.
    b. This has been a problematic application. One phase fuse blows, but its loss is hidden by the supply of that phase to the LV network from other network transformers. Then single-phase operation of an unmonitored transformer causes heating and subsequent failure under load.
    c. Even if other LV network sources disconnect in response to the fault, the unblown sound phases can backfeed and sustain the fault arc through capacitive or apparatus coupling.
    d. This single-phasing issue might be mitigated with electronic fuses with the cross-triggered operation.
    e. Fuses offer little improvement of fault sensitivity over substation feeder relays. Fault currents below maximum load capability, including many secondary faults, will not blow fuses.
2. Distance relaying at the substation has been tried in the past.
    a. Modern distance relaying elements in microprocessor relays distinguish symmetric load currents from symmetrical or unsymmetrical fault currents with complex impedance criteria far more sensitive and selective than overcurrent relays.

    b. With this ability, distance relays can reach much further into the transformer primary or even into part of the secondary wiring for unbalanced and some balanced faults.
    c. Distance relays still do not cover the entire transformer or the LV components. An uncleared LV fault might be detected sooner when less of the transformer has been destroyed. This will not save the transformer but may reduce fire, damage, and explosion risk.
    d. In a new product development or new application, the relay can implement special logic and/or measurements to improve selectivity for various operating conditions unique to feeders of mesh or spot networks.
    e. Existing measurement methods, including load angle restriction and loss-of-potential logic, overcome some legacy application concerns.
    f. Distance relaying elements are inherently directional and would be more accommodating of reverse energy flow (when allowed from the load end) without compromising fault protection.
    g. The newest multifunctional microprocessor distance relays for utility transmission service have a platform cost low enough to make the total installed cost of such relays indistinguishable from older distribution feeder relays.
    h. Self-monitoring and communicating modern relays bring significant reliability improvements and operational cost savings, as explained further below.
3. Transformer differential protection (87T) has been used and requires primary CTs.
    a. These CTs have other positive impacts and are discussed in the next section.
    b. 87T is fast, selective, and sensitive to all faults between primary and secondary CTs.
    c. Sensitive clearing of transformer faults requires either a high-side breaker on the network transformer or a transfer-tripping means to the substation. Other new options are discussed below.
    d. The gap between the secondary CTs on the secondary source and the NP contacts is not covered by 87T.
    e. The NP or 87T using existing secondary CTs do not cover faults from those CTs to the first protective device downstream from the protector. Downstream fuses or fusible links may not de-energize the LV network for a lower-current fault in this zone.
    f. Output CTs can be added for coverage of the above fault scenario by expanding the 87T zone to the load terminals of the protector.
4. Reverse-looking distance relay protects for transformer fault backfeed from the LV network.
    a. It has the potential to coordinate with high-side or substation overcurrent or distance protection to improve coverage of transformer faults.
    b. The study is required to determine if removal of LV fault backfeed improves high-side coverage to assure sequential removal of most or faults on LV or MV windings. It includes a comparison of behavior with a modern network relay whose reverse current sensitivity is higher at high angles and is reduced to allow a small backfeed at load angles.
    c. It should be practical for the distance element to discriminate between reverse load flow if otherwise allowed from DER in LV network and reverse fault current with associated voltage change.
    d. Functionality would be added to the network relay. Loss of potential supervision is included.

Non-electrical transformer fault sensing solutions are discussed further below.

4.3. Instrument Transformers for Protection and Control

Additional CTs can greatly improve fault protection of network transformers and vaults and offer opportunities for improved network operation. These improvements include an improved ability to distinguish between faults and the DER-induced energy outflow that the industry may want to allow in the future.

Additional PTs or voltage sensors can detect and report various normal and abnormal operating conditions, including unbalance, grounding and neutral problems, and under-or overvoltage conditions.

4.3.1. Issues

1. Conventional iron-core relaying CTs have been installed on the primary side of the network transformer by some utilities to supply a transformer differential 87T relay as described in the prior subsection.
2. These CTs are installed in only a small minority of installations due to the cost and/or space limitations. (A percentage is not yet supported with data and might be a topic in a casual survey with upcoming utility interviewees).
3. The 87T relay does not help unless there is a local breaker or fault interrupter or a means of sending a transfer-tip command to the substation breaker. For additional options see the fault shunting discussion in Section 4.4.
4. The CT cost issue is exacerbated by the additional 87T relay and the high-side breaker or interrupter cost to achieve a high-impact low-probability benefit without a convincing business case at construction time.
5. As suggested below, the business case might be improved with a holistic microprocessor-based protection solution for the transformer and protector supply system.
6. The interview with ConEdison documented in Chapter 3 revealed that additional low-cost voltage sensors could expose operating situations and issues hidden before these sensors were available and easy to apply. Con Edison uses Micatu optical fiber voltage sensors which are easy to install in limited spaces. They report value from observing problems with neutral and ground connections, high and low operating voltages, and malfunctioning power switches or breakers.

4.3.2. Solutions: Limits, Practicality, and Economics

1. Rogowski coil (Figure 4-1): A compact pancake-like air-core CT with precision mechanical secondary wound conductor or circuit-board layout for high measurement accuracy.

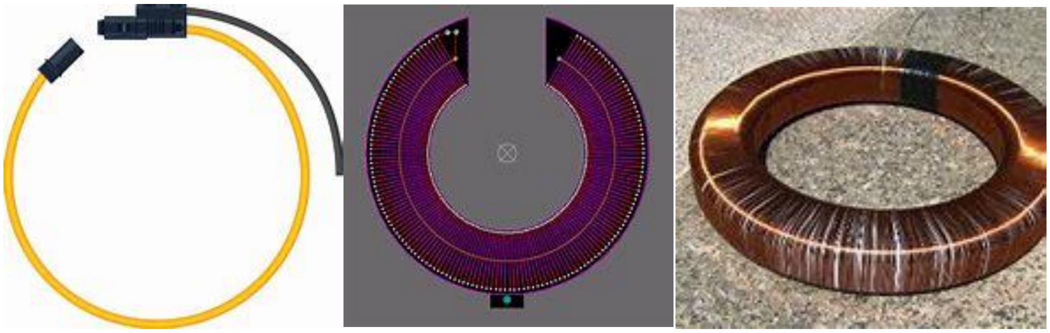

Figure 4-1. Examples of Rogowski Coils

   a. Rogowski coils are extremely compact and fit in tight spaces like shipboard distribution switchgear.
   b. Air-core measurement is linear over any current range and eliminates saturation limits associated with high fault currents, as well as low-end magnetizing branch errors at low currents.
   c. Linearity in the presence of unlimited current flows can simplify 87T design, improving sensitivity and security.
   d. Bandwidth is unlimited in a power-system context. High 87T response speed and auxiliary power quality, and harmonic measurements are supported.
   e. Developers have created split-sensor designs which can be installed on an existing primary conductor without disconnection.
   f. The output of the Rogowski coil is a weak-source voltage requiring a high-impedance or low-burden input of an electronic or microprocessor relay with A/D converter interface (but is not a challenge for such a relay as long as the output voltage for the highest-current fault does not exceed the A/D converter input maximum). Please keep the fault current and relay A/D input limit in mind when choosing the turns ratio or volt-to-ampere ratio.
   g. The output voltage of the Rogowski coil is proportional to dI/dt. The user must compensate in the relay for a 90-degree leading phase shift of output voltage to primary current for power-frequency currents. The current change rate dI/dt may accentuate transients and harmonics. Mathematical integration by relay algorithms (or a front-end analog operational-amplifier integrator circuit) can compensate for phase shift and transient sensitivity.
   h. Rogowski coils do not need the heavy-gauge secondary wiring of iron-core CTs with 1 p.u. = 5 A. However, avoid any risk of noise pickup in the LV output circuit by using a twisted-pair and optionally shielded connection with limited run length.
   i. Rogowski coils do not present hazardous voltages to maintenance technicians who accidentally open the secondary circuit of a load-carrying feeder.
   j. Rogowski coils and relays with suitable inputs are available as commercial products. Input circuit designs can be adapted to network relays.

2. Optical CTs
    a. Magneto-optic current transducers (MOCTs) (Figure 4-2) are all-dielectric components that use a bulk machined glass sensor or specially-prepared optical fiber segment to detect magnetic fields from current flow in a conductor surrounded by the glass measuring medium. According to the Faraday effect, the magnetic field around a current-carrying conductor is measured by the instantaneous angular shift of polarized light passing through the glass. A polarized light-emitting source and polarized photodetector are connected to the glass measuring element by optical fibers for dielectric isolation of the energized installation. The light source and detector are elements in a compatible protective relay or meter or are installed as a stand-alone electronic interface with a LV output that replicates the primary current waveform.
    b. Optical CTs have been available for utility applications in transmission since 1990. However, their use is not widespread since the higher cost was not balanced against transmission substation space, weight, and insulator cost savings. Since each three-phase measurement set in a transmission substation required six dedicated optical fiber runs to the control building, these CTs are only now becoming more attractive as the utility industry enters the era of IEC 61850-9-2/61869-9 switchyard merging units (MUs). MUs are installed near or inside ITs, an apparatus for short, direct field signal and control connections. An MU converts the bundled mass of individual phase analog signals (fiber pairs with MOCT or optical voltage sensor) into multiplexed data streams sent back to relays on a single fiber pair per MU.

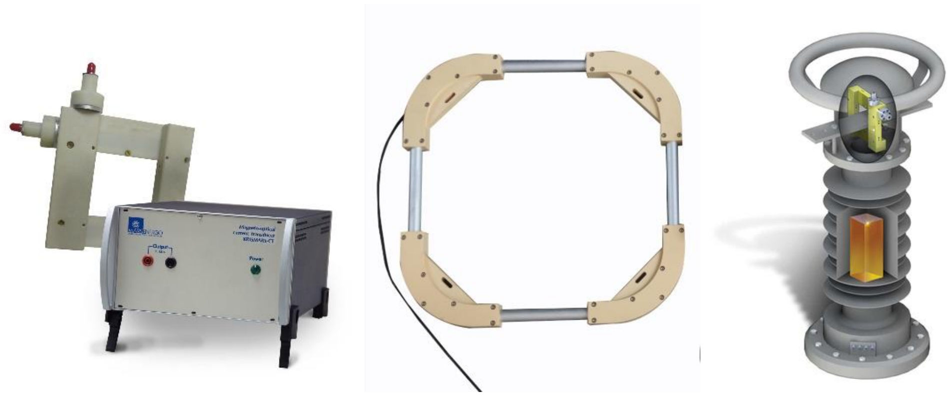

Figure 4-2. Examples of MOCTs (in Bushing Assembly, MOCT Is the Green Object in Cutaway on the Right)

    c. Optical CTs have not been used for distribution because of cost and a lack of direct interface compatibility with widely used relays. However, there are industry experts now developing distribution MV feeder optical sensors that target acceptable costs. The resulting products are not yet commercially available.
    d. Optical CTs are potentially small, slim, and easy to install, with all-glass construction to avoid insulation design challenges or fault vulnerability.
    e. Fiber runs to interfaces of microprocessor relays are environmentally immune.
    f. Optical CTs are linear to any current magnitude with no saturation effects. Fault and differential measurements are simplified with improved dependability and security as with Rogowski coils.
    g. Bandwidth is unlimited in the context of power system applications.
    h. There are no hazardous voltages associated with the opening of a secondary electrical circuit.

3. Existing distribution line post sensors of recent design (see Figure 4-3) are easy to install on existing primary conductors without disconnecting primary circuits.
   a. LV analog outputs require microprocessor relays or meters but do not present hazardous voltages when open-circuited.
   b. Existing products are accurate to better than 1% for load currents up to 600 A but are not designed to reproduce higher fault currents. Any initiative to use such sensors for protection applications would require an investigation with a manufacturer on the possibility of building research units with profoundly lower current sensitivity to measure 20 to 40 p.u. fault currents without waveform-limiting effects.
   c. In the case of such investigation, it is logical to inquire about a unit with separate metering and relaying outputs on a shared core.

Figure 4-3. Example of Outdoor Line Post Sensor (Lindsey Manufacturing Company).

4. Hall sensors for LV conductors
   a. A Hall sensor is an electronic field measurement element inserted in a gapped magnetic core that can report current waveforms with large bandwidth.
   b. The hall sensor connects to a purpose-designed measurement intelligent electronic device (IED) or relay that can energize the sensor electronics and process its analog output of instantaneous current value.
   c. Hall sensors are readily installed on system wiring for insulated instrumentation but have not been widely applied for protective relaying. There is no obvious barrier if magnetic saturation and dynamic range requirements are considered in the design.
   d. Hall sensor magnetic cores can be designed as split cores for installation around an existing conductor.
   e. A Hall sensor may be a good solution for a doughnut current measuring device that surrounds three or four LV power service conductors.
   f. A Hall sensor may be a good solution for a doughnut current measuring device surrounding three or four LV power service conductors to report residual ground-fault current.

4.3.3. Benefits of New Current Measurements

Easy-to-install current measuring devices on the MV network transformer primary and/or on the LV output from NPs could bring the following benefits explained in other sections of this chapter:

1. The sensitive and selective differential fault protection of transformer out to secondary CT or new output CT (no unprotected zones).
2. Feeder differential or directional protection (with communications addressed below).
3. An improved and selective operating characteristic of 32 reverse watts or reverse watt-var network relay function because the transformer's exciting current does not require setting

allowance. This supports scenarios of managed outflow or minimized inflow resulting from DER operating within the secondary network.

4. An ability to utilize local fault tripping or shunting to speed clearing, reduce damage and fire risk, and ease coordination demands on remote relays. This includes coordination challenges when substation bus fault duty is impacted in a daily cycle by high penetration of DER in the vicinity. Bus duty may drop significantly when DER is in full production, leading to the miscoordination of legacy relaying. California utility transmission protection engineers are already measuring and observing these large decreases in bus fault duty at times of high solar energy production, raising concerns over relay coordination.

4.4. Fault Clearing Methods

4.4.1. Issues

1. In most installations, faults between the network transformer primary terminals and the NP must be cleared by the substation feeder relaying, which detects the fault and trips the breaker.
2. Sections 4.2 and 4.3 brought the possibility for local sensitive and selective detection of faults in this problematic zone, but the isolation of the fault requires a means of removing the MV fault current contribution.
3. As we already observed, many faults in the transformer or on its secondary connections may be detected and cleared from the distribution substation only after they cause enough transformer or vault damage to create a primary-side fault.
4. Transformer primary breakers are not always installed because of space requirements and cost.

4.4.2. Solutions: Limits, Practicality, and Economics

1. A local 87T relay trips primary-side compact vacuum fault interrupters or MV breakers, which are used in some installations.
   a. Interrupting time of a vacuum breaker is about two cycles, compared to five cycles for other circuit breakers.
   b. Vacuum interrupter assembly has a smaller footprint than an MV circuit breaker.
   c. Vacuum interrupters may or may not have automatic reclosing and re-tripping capability. This difference is acceptable when the operation is only for the clearing of rare fault types.
   d. Disconnection by local relaying and vacuum interrupter before the feeder relay operates avoids substation tripping and keeps other transformers and networks on the feeder energized.
2. Local 87T relay sends a transfer-trip signal to the substation breaker.
   a. Faster fault clearing than waiting for remote 50/51 relay pickup.
   b. Other transformers on the same feeder are de-energized.
   c. Requires low-latency (typically 2-16 ms) secure communications of the trip command via a medium that can be costly to install or lease. Optical fibers installed in parallel to the feeder path during installation have minimal marginal cost.
   d. Legacy copper wire channels are vulnerable to degradation, and terminal equipment is obsolete.
   e. Leased common-carrier copper wire channels are becoming expensive or unavailable.
   f. New common carrier services can be costly and require data communications interfaces, as explained in Section 4.6 below.

g. All wire channels are subject to induced and intense interference from adjacent power circuits, especially during faults. Isolating or neutralizing induced power-frequency voltages on communications wire pairs is not well supported by today's workforce knowledge or product solutions.

3. Close a primary grounding switch to shunt fault current.
   a. This replicates a 1950s scheme of transfer-tripping in transmission applications when communications were not available. An electrically triggered explosive charge (like a shotgun shell) operates a single-phase switch blade to rapidly apply a solid phase-to-ground fault that is quickly detected and cleared by remote relays.
   b. If developed, an MV shorting-prong version could operate much faster than old long-arm transmission grounding switches—several milliseconds is proposed as a practical objective.
   c. A three-phase shorting switch shunts fault current away from the transformer and NP apparatus after just a few milliseconds. Fault damage would be far less than for the fastest substation breaker or vacuum interrupter tripping, minimizing vault damage or fire or explosion risk.
   d. The fault removal speed benefit is multiplied using the optical arc flash sensing methods described in the next section.
   e. Other transformers on the shunted feeder circuit will be de-energized.
4. Eaton Electrical switchgear and protection development engineers with whom the author spoke described a similar concept already implemented in a new fault-shunting solution for metal-enclosed switchgear. A vacuum shunting switch, similar to an interrupting vacuum bottle, is triggered by optical sensors with a response of a few milliseconds to minimize arc flash hazards and compartment damage.
5. Electronic fuses are installed on the primary side of the transformer.
   a. Sensitivity is limited. Overcurrent operation may not pick up for some faults between the fuses and the NP.
   b. The ability to be triggered by 87T or other relay is required for full isolation capability.
   c. The ability to cross-trigger among phases is also important to avoid sustained single-phase operation of transformer or back-feeding of fault arc from sound phase coupling.
   d. As with a local breaker or interrupter, a fast or relay-triggered fuse operation avoids feeder tripping and keeps other transformers or networks energized.

4.5. LV Network Electrical Fault-Sensing Methods

Arcing LV ground faults may not blow fuses and may be impossible to localize due to multiple grounding connections or lack of measuring capability. This may be partially overcome with new secondary phase current measurements and processing described in this section.

4.5.1. Issues

1. In most installations, protection for faults on the secondary LV network comprises fusible links and fuses that open only for fault currents well above load.
   a. Fuse operation can often isolate the faulted network section and allow other zones to remain in service.
2. Some installations have protective relays and CTs on secondary neutral grounding paths to trip for ground faults whose magnitude is less than the load current.
3. Ground fault protection, if used, is not generally able to determine fault location within the network so that the entire network is de-energized.
4. Fuses and ground fault protection must be coordinated with trip units or protective devices in load service switchgear by time delay. Load protective devices must trip first for faults in or beyond the switchgear to avoid clearing the LV network section.
5. Arcing ground faults may present the unfavorable combination of low fault current that does not pick up protective devices with high temperatures and extensive physical damage.
   a. 120/208 V network arcing ground faults will sometimes burn clear, but 277/480 V networks will sustain the arc until the damage leads to a detectable fault, by which time fire and smoke damage may be extensive.
6. The literature study found no discussion of predictive diagnostic techniques applied to LV network equipment.

4.5.2. Solutions: Limits, Practicality, and Economics

1. More measurement points on transformer neutral grounding connections and LV system grounding connections.
   a. In many installations, the transformer secondary wye neutral connections are brought out of the transformer enclosure by insulated busbar into the service bus enclosure so that each neutral can have its own CT and more sensitive relay in addition to a CT and relay where the neutral service bus is grounded.
   b. The improvement opportunity comprises isolating LV network busway and enclosures to allow grounding in zones that each can have one grounding point with a CT or current measuring devices. However, to gain any benefit beyond just post-event fault location, there must be breakers or triggerable fusing devices that can isolate the faulted section. The ability to separate the grounding of sections may be limited by multiple-point bus work grounding requirements of the National Electric Code. Multiple ground currents would have to be summed in a yet-to-be-developed economical distributed measurement system.
   c. LV cable runs between LV network sections often comprise multiple parallel cables, each separately fused, so that if one cable is faulted and blows its fuses, the redundant parallel cables maintain the connection. The ground fault sensitivity is still limited by the fuse pickup current that coordinates with downstream devices.

2. Doughnut CTs have been applied for decades to surround the three-phase conductors, or those conductors with a neutral return, to energize relays and sensitively detect ground faults.
   a. Existing large CTs and relays may be difficult to fit and expensive to apply.
   b. The protection is based on residual overcurrent and is still not selective of fault location.
   c. Coordination delay is still required, and there are some fault situations where the residual CT scheme may not work at all even though it is worth installing (see Shields, [5] in Chapter 3).
3. An LV network ground differential scheme could be developed as described in the following:
   a. One surveyed utility installs CTs and relays for differential protection of the entire LV network, with 15 cycle delay, tripping primary breakers.
   b. As a retrofittable scheme, install compact, low-cost doughnut residual CTs based on Rogowski coils or Hall sensors, each reporting residual current from a service entrance or exit point on a section of the LV network.
   c. CT electronics report current measurements as a series of digitized data values on LV twisted pair conductors or optical fibers.
   d. Wires or fibers connect to a receiving protective unit which sums the current values from the CT locations.
   e. For a ground fault within the zone surrounded by the CTs, the sum will equal the fault current. The measurement is immune to load or faults outside the zone surrounded by the CTs.
   f. The protective unit can issue an instantaneous trip signal to protectors or available LV breakers, coordinated with fuses or other protective devices, which the application engineer would like to operate first for isolation if possible. MV supply breakers can be tripped if available.
   g. One simplified application scheme would place one such CT at each NP's output for clearing the entire network for an otherwise-uncleared ground fault.
4. A version of the differential scheme of (#3 above) can place a sensor on each of three or four conductors for backup phase fault protection and ground fault protection of the entire LV network or a segment. Ground fault sensitivity is only slightly reduced according to measurement errors of each phase CT.
5. A version of the scheme (#3 or #4 above) can be implemented with Wi-Fi-like wireless network communications.
   a. Section 4.7 below discusses cybersecurity measures for data protection and authentication to foil a cyberattack that could cause tripping and blackout of the facility.
   b. A denial-of-service attack such as jamming, or even unintended interference from failed electrical machinery, could disable the protection instead of causing misoperation. Protection then falls back to what fuses and links provide today. However, the protective unit would immediately alarm maintenance personnel for the loss of valid received measurements, leading to quick repair of the system after failure or discovering the interference source.

6. Waveform signature analysis:
    a. Some research and development may already have been done on the waveform signature for an arcing fault based on time-domain and/or harmonic pattern recognition.
    b. LV arc-fault circuit interrupters are in widespread use, detecting low-current arcing faults by distinctive time-domain signatures.
    c. Research decades ago, at the emergence of residential arc fault breakers, had not yet found effective patterns for securely detecting faults in 480 V industrial systems.
    d. A major risk is a normal and acceptable electrical event that mimics the pattern. For example, arc fault breakers may trip when an incandescent light bulb fails with arcing across the failed filament ends. In industrial applications, large load contactors and switches may generate arcs. Sufficient tripping time delay may mitigate the risk.
    e. Electric utilities have experimented for decades with distribution protective relays that detect high-impedance ground faults with waveform analysis. Results have been inconclusive, with incorrect operation as a major drawback. Connecting the output to the alarm has produced false alarms leading to fruitless field circuit patrols and has undermined confidence. A new generation of waveform-analysis relays is now under test by certain utilities.
7. Predictive monitoring and analytics:
    a. For substation apparatus, RF sensors are used to detect impending breakdown or failures of insulation. This work has not yet determined if LV apparatus with insulation degradation has a prospect of emitting radio frequency interference that a monitoring receiver can distinguish to alarm before a fault occurs. The investigator's experience suggests that such emissions are common. Sources should be found and corrected even though some sources may be load problems and not leading to faults.
    b. High-frequency discharge signals measured on electrical conductors may also be precursors of faults. This work has not yet determined if LV apparatus with insulation degradation has a prospect of generating electrical noise that can be distinguished by a monitoring IED coupled to an instrument transformer or primary busbar conductors. Investigation might comprise spectral analysis of electrical signatures from operating apparatus in old LV network installations to benchmark normal or unusual signatures and sources of the noise.

4.6. Non-Electrical Fault Sensing Methods

4.6.1. Issues

1. The electrical detection means listed in prior sections may not detect all arcing LV ground faults.
2. There are notable cases of LV ground faults that sustain with dramatic arcing and damage for seconds or minutes until it evolves into a more serious fault that is cleared by electrical sensing—after significant installation damage, fire, or explosion.
3. Sudden-pressure or fault-pressure-change relays on transformers are challenging to maintain. They are often not maintained and suffer hidden failures.
4. Sudden-pressure relays sometimes trip for external faults or seismic events and physical disturbances.

4.6.2. Solutions: Limits, Practicality, and Economics

1. Fault arc or ultraviolet (UV) optical sensing:

a. Roop & Vadonic of Virginia Electric Power demonstrated effective arc detection and tripping with sensors that detect UV arc light emissions.
b. Sensors must be ubiquitously deployed for exposure to all arc fault locations to be covered.
c. Arc sensors are now widely deployed in metal-enclosed switchgear for fast tripping and arc flash energy limitation.
d. In the last decade, there has been significant optical sensing development with optical fiber sensors and electronic protection units for easier and more complete coverage.
e. The Oncor interview (Chapter 3) and data revealed their adoption of a customer LV supply relay and backup transformer outfeed relay, type SEL-751 with optical fiber arc flash sensing fiber input. They reported very high speed and completely reliable detection of faults in testing, with no problematic response to ambient light sources. The sensing fibers are reported to be easy to route and install.

2. Thermal or IR sensing:
   a. Fault heat sensors have already been applied in unprotected or inadequately protected zones of transformers, protectors, and bus work.
   b. Heat or IR sensors, as with UV sensors, must be ubiquitously deployed for exposure to all arc fault locations to be covered.
   c. Lower-cost thermal imaging cameras based on IR diode detector arrays are available with visual pattern recognition processing to report extreme events like faults in a fraction of second and degradation failures such as corroded or loose overheating bus connections not yet faulted. These have been effectively applied in substation switchyards for equipment monitoring. There must be a camera placement location that provides the field of view for helpful protection.

4.7. Communications Opportunities

4.7.1. Issues

1. Existing time-coordinated overcurrent protection schemes depend on predictable fault duty, which may be lost as DER penetrates the entire transmission and distribution system. Coordination and sensitivity may become challenging.
2. The time-coordinated schemes limit the allowable penetration of DER to a facility to a value below the minimum facility load presented to the utility supply before DER. Improving energy use efficiency in the facility will unpredictably exacerbate the problem and increase the risk of outflow tripping.
3. One theme running throughout this report is that current differential (87/87N) protection schemes are the most sensitive, selective, and fast-clearing tools for improved fault protection, as well as reduced hazards and damage. However, these schemes require substantial wiring within the facility or communications between ends of a feeder, impacting affordability.
4. In best practices for protection within facilities, 87 schemes are applied today with CTs around the protected zone (typically a network transformer or the LV network itself) and heavy-current wiring connected to relays at a substantial cost.
5. Wiring within facilities is expensive to install, requires careful commissioning.
6. Wired facilities are vulnerable to flooding and contamination.
7. Wired protection schemes must be periodically tested and may suffer hidden failures that persist for years between tests or until an uncleared fault exposes the problem.

8. Ethernet and fiber communications are becoming ubiquitous, and costs are decreasing, but they have application and cybersecurity challenges.
9. Utilities continue to struggle with the cost and difficulty of providing SCADA communications to LV NPs, control systems, and DER that must be coordinated with LV network protection.

4.7.2. Solutions: Limits, Practicality, and Economics

1. Install 87/87N protection around zones in network facilities, overlapping zones around transformers and protectors, and encompassing the connected LV network, or even covering it in sections.
   a. Current differential schemes support the industry's forecasted transition to large DER penetration within facilities served by LV networks, tolerating arbitrary load flows in or out with no loss of protection capability or loss of protection coordination.
   b. They reduce engineering of and reliance on time coordination of protection elements through the entire chain as utility bus duties become less predictable in the future.
   c. Current differential schemes are well suited to self-monitoring of measurement and protection systems, alarming failures for immediate repair, and eliminating periodic maintenance costs.
2. Install current differential feeder protection (87L) schemes on top of overcurrent 50/51 schemes for the same benefits of speed, sensitivity, selectivity, and tolerance of DER with arbitrary flow directions.
   a. 87L requires a data communications channel among the utility substation and the served facilities for derived current comparison values.
   b. Copper wire analog connections of the past are obsolete.
   c. Install optical fibers to carry data among relays at the feeder terminals. Fibers are easy to install simultaneously as the feeder cables or in their tunnels but may be expensive to run on a separate path or in a retrofit project.
3. Replace wiring for protection, control, and monitoring with optical fibers carrying IEC 61850 messaging services, now widely used in utility substations.
   a. IEC 61850 services on ethernet fibers include high-speed sampled values (SV) signal-transport service, and millisecond-speed status reporting and control by GOOSE and routable GOOSE (R-GOOSE) services, along with a range of information-sharing and system configuration services, to handle all transport except final control output or measurement input within the apparatus.
   b. Develop compact MUs—control and data acquisition interfaces installed inside the submersible transformer and NP vaults—to convey information for relaying and SCADA to IEDs in a separate protected enclosure or remote protected environment.
   c. Optical fiber connections with IEC 61850 traffic are contamination and flood-resistant and can be run long distances. They have good heat resistance.
   d. Communications of measurements and control signals outside the NP vault and facility enclosures and rooms expand the prospects for improved protection schemes suggested in this report, including 87 protection and system monitoring.
   e. P&C at ConEdison's East 13th Street substation in Manhattan was rendered unserviceable in a 2013 Hurricane Sandy flooding event. The replacement P&C installation uses submersible relay enclosures with waterproof connectors and a limited count of IEC 61850 optical fibers in place of the failed mass of conventional wiring. Entergy in Louisiana is installing new

control buildings on stilts above Hurricane Katrina flood levels with IEC 61850 optical fiber communications and submersible MUs.

   f. IEC 61850 specifications model a long list of power system functional elements (logical nodes or LNs) and specify standard communications information fields and exchanges among the LNs in each protection or control device. This standardization of information exchange leads to automation of the facility engineering process at the function and topology level, eliminating the time and cost of drawing out every wired point connection or mapping out communications point lists.
   g. Installation and commissioning comprise connecting fibers among IEDs and confirming functional communications in far less time than legacy P&C wiring and commissioning. Communications and IED monitoring in service eliminates periodic maintenance testing and reports failures as soon as they occur—a reliability benefit this report has emphasized elsewhere.
   h. For some services implemented in IEC 61850, there is a competing communications protocol to consider, called *OpenFMB*. It is favored by some utilities in research projects.
4. Specify and demonstrate a secure protocol for utility-owned or common-carrier ethernet high-speed wide-area network (WAN) transport, based on industry-standard services and protocols.
   a. Secure measurements from network vaults and DER installations can support the management of DER production versus facility load.
   b. DNP3 SCADA protocol implementers are developing new secure service versions.
   c. IEC 61850 client-server communications must be supported with IEC 62351-6 specified security services.
   d. IEC 61850 R-GOOSE provides high-speed control capability over a WAN, such as transfer tripping from the LV network facility to the utility substation breaker. It includes encryption and secure key-based hashing for authentication of high-speed control message packets (so receiving IED is confident that the packet came from the intended source device and was not inserted in a network security breach).
   e. IEC 61850 Routable Sampled Values (R-SV) gives similar secure high-speed transport for streamed measurement values.
   f. Both R-GOOSE and R-SV services automatically associate publishers of and subscribers to packet streams over a WAN using IT standard Internet Gateway Management Protocol Version 3, easing installation configuration and path maintenance.
   g. At the time of writing, Triangle Microworks (a respected utility industry communications software product vendor) is introducing a public key infrastructure—a key distribution center system with protective relaying grade redundancy and robustness to support the authentication key requirements of R-GOOSE and R-SV.

5. Specify secure communications for Wi-Fi-based differential schemes as explained in subsection 4.5.2 (5.) above.
   a. R-SV or encrypted non-routable SV is suitable for synchrophasor current measurement sharing.
   b. R-GOOSE or encrypted GOOSE is suitable for high-speed commands like tripping if needed.
6. Initiate study review of economics and vulnerabilities of communications solutions for SCADA data gathering and control of LV network protection devices and systems.

a. List specifications (such as data rate, latency, availability) with tiers of limits versus application use cases or functions that are supported, poorly supported, or not supported.
b. Develop a list of low-cost communications solutions and analyze the prospective behavior of each – e.g., fiber network, AMI radio, Wi-Fi, mesh data radio, Bluetooth, proprietary communications, cellular service, and others. Assess suitability for environments where LV networks are found. Match to specifications list and estimate cost per node.
c. Con Edison reported during interviews that it is transitioning from power line carrier SCADA communications to common-carrier cellular data service from Verizon. With thousands of installations, this appears to be a practical option.

7. Determine candidates for trial development and demonstration.

4.8. Condition Monitoring of Protectors and Circuit Breakers

Section 4.1 discusses issues and solutions for improving the reliability of LV network installations based on existing equipment and designs. Condition monitoring of NPs and breakers is recommended there as an effective reliability aid and maintenance cost reduction.

Subsection 4.1.2 (3.) suggests relay timing of breaker or protector operations in service as a supplement to or replacement for periodic maintenance tests. Breaker monitoring functions in relays or control IEDS check the timing of when the device is tripped or closed. Figure 4-4 shows simple logic developed by the author of this report for an EPRI demonstration of the effective timing of 69 kV utility breakers. It identified a problem fleet for replacement and now supports a low-maintenance asset management program for the replacement breakers. This logic is implemented in a simple utility relay and is practical to implement in computing platforms like those used for NP relays.

Unlike disruptive maintenance tests, the timing logic will catch slow breakers or protectors on the first trip event after a long period of inactivity. This shows timing problems from a lack of operation before the mechanism can free itself on the first trip.

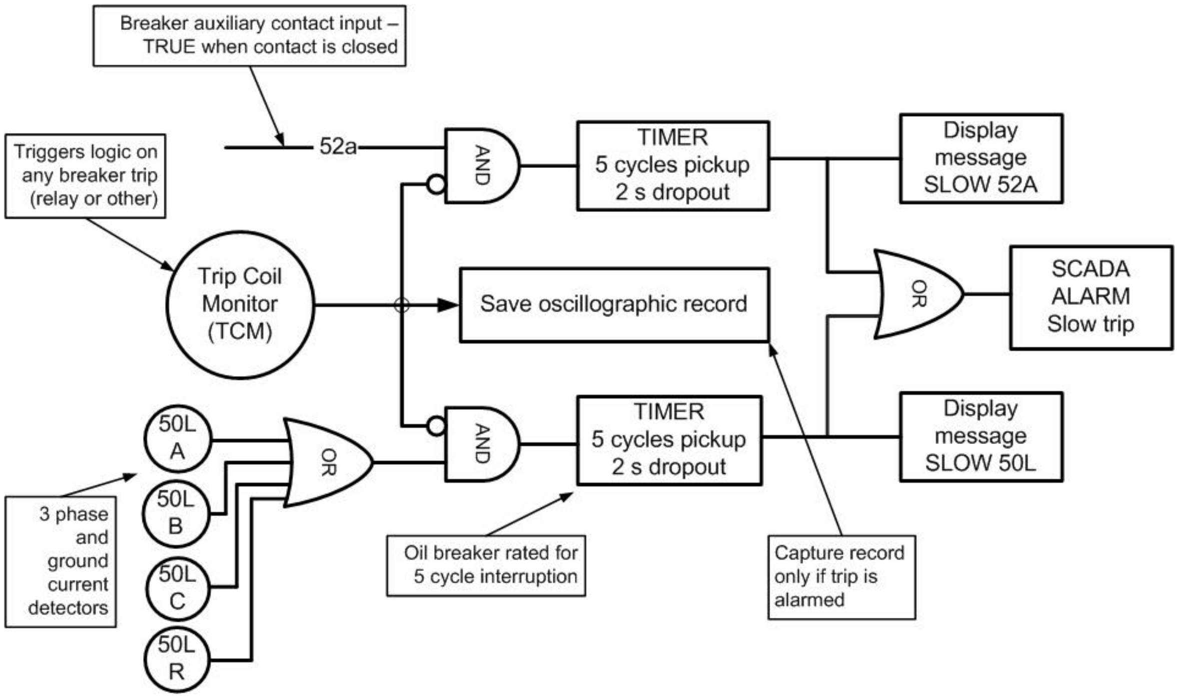

Figure 4-4. Breaker or Protector Operation Timing Logic [15]

4.9. Condition Monitoring of Protection Systems

4.9.1. Issues

1. Network relays and other fault protection relays and their wiring may sit idle for decades, and only maintenance tests or uncleared faults will expose a failed protection system component.
2. Periodic maintenance testing is costly and risks disturbing, reconfiguring, or damaging system components. It occasionally leads to serious human error and an outage or damage event.

4.9.2. Solutions: Limits, Practicality, and Economics

1. A basic design principle for new utility P&C systems is using the built-in self-monitoring capabilities of microprocessor relays, in combination with heartbeat data communications among different relaying elements, to detect and alarm for all failures and eliminate the need for periodic maintenance testing.
2. Either loss of expected communications by a receiver/subscriber or failure of a computing component within the IED yields a specific alarm with troubleshooting evidence, via a heartbeat alarming communications path, to a location where the alarm results in maintenance attention.
3. The overall P&C system must be designed with no unmonitored gaps among elements, such as quiescent wired connections. This is practical in new protection scheme designs, especially with IEC 61850 services.

4. A condition-based maintenance program based on monitoring and alarming is even more effective if the configuration or settings of the IEDs can be periodically polled by an external monitoring system or SCADA location so that settings can be confirmed to be as intended (identical to a managed settings archive) and have not been tampered with by field maintenance personnel.

4.10. Steady-State Operation of LV Network with DER

DER includes both generation—photovoltaic, wind, or combined heat and power (CHP)—and BESSs or other storage technologies.

4.10.1. Issues

1. Existing protection schemes tolerate little or no export of energy and will trip protectors.
2. If the utility supply is lost, DER must disconnect and not carry local loads.
3. Studies cited in references have focused on limited DER connected to an LV network and have not yet shown experience of operating problems.
4. Studies and practices reviewed so far recommend that the maximum possible DER output be less than 20% of minimum daytime load or less than 30% of the absolute minimum load.
    a. Based on experience to date, ConEdison has modified its connection requirements to allow larger DER connections in customer LV networks they serve than previously were allowed. No serious problems have been reported with protection; new relay characteristics are available for improved tolerance.
5. DER applications need to balance supply reliability with load backfeed risk limitation and minimization of fault current delivery.
    a. Inverters should limit or remove levels of the local generation that risk excessive backfeed and supply feeder tripping.
    b. Inverters should ride through typical disturbances beyond the source feeders that are remotely cleared yet should block output or shut down for faults in the LV network supply. This should be true even if DER backfeed is allowed under normal load conditions.
6. Protection coordination software now used for all new installation validations may not accurately model the behavior of DER in normal operation and during faults, leading to misoperations in service.

4.10.2. Solutions: Limits, Practicality, and Economics

1. Present schemes limit DER outfeed and risk tripping, but tolerance is increasing. Some adjustments of existing protection characteristics can tolerate DER production closer to the facility loading.
    a. The Richards MNPR network relay is observed to offer a trip characteristic option with a short-time tolerance (minutes) before tripping for small (e.g., 5%) load outflow.
    b. The published Eaton MPCV relay characteristics do not indicate that this capability is available, although the feature may have been easily developed if a customer requested it.
    c. Both relays offer adaptive transition of watt to watt-var reverse trip (32) characteristics.
2. Sections 4.2 through 4.5 have presented how increasing the use of current differential protection across multiple zones of the distribution system down to the LV network improves fault sensitivity, speed, and selectivity while tolerating outflow of DER production to the utility substation.

3. Similarly, current differential protection will reduce coordination challenges as DER operation causes changes in fault duty on the utility supply bus over a day.
4. Inverters associated with DER must detect islanding conditions – loss of all utility supply – and be shut down.
   a. This is accomplished by inverter controls that push or pull on the utility supply as they follow its phase and frequency to detect islanding.
   b. If microgrid operation of the LV network is to be enabled, one or more inverters must transition to grid forming mode as the microgrid control system sheds facility load to balance with the available local energy supply.
   c. More sophisticated automatic synchronizing functions may need to replace the existing phasing relay close-blocking function if the microgrid LV network is to reconnect with a reenergized utility feeder automatically.
5. DER inverters should be able to ride through disturbances while disconnecting/blocking or reducing energy production for excessive backfeed.
   a. Standardize scheme as described in the literature to block or throttle inverter output if excessive in proportion to LV network load.
   b. Develop standardized application behavior in which total LV network load can be communicated to control inverter output and limit backfeed risk.
   c. Inverters should respond to voltage and frequency disturbances per IEEE 1547 with recent provisions for transient or remote fault ride-through to avoid needless grid-stressing loss of generation just when it is needed.
   d. Provide inverter blocking command for locally detected LV network or supply fault.
6. Engineering study software is routinely used for the analysis of fault coordination and non-fault operation of LV networks.
   a. Common distribution tools include CYME and SKM.
   b. The status of modeling for PV with inverters, wind generation of four behavior types, BESSs, and other sources to be listed requires investigation. Inaccurate models of DER behavior will lead to misoperations of protection in service or under non-fault conditions.
   c. For utility T&D coordination programs like Aspen OneLiner and CAPE, program suppliers are struggling to provide utility customers with valid models of DER at this time, so the risk is serious.
   d. Inverter manufacturers have kept the fault behavior of their products a secret or have supplied demonstrably lacking models.
   e. There is an industry effort and need for clarity in required behavior and the behavior expected from inverters in service. Efforts related to DER in LV networks must tie into these broader initiatives, active with the North American Electric Reliability Corporation on the utility and high-voltage network side.
   f. Distribution industry activities in modeling issues for DER are a topic for study in continuing phases of work.
7. The power electronic inverter systems supplied for DER generation and/or BESS might be combined or functionally integrated into a new architecture for LV network control and protection, especially in a microgrid-capable design.
   a. Begin with physical layout prospects when functionalities are combined this way.
   b. At the time of this report's writing, this is not assured of being practical or helpful until additional design conception is considered.

5. RESEARCH RECOMMENDATIONS

The following recommendations are collected from the prior proposals and sorted into categories of improvements to existing designs, retrofittable scheme additions, and new system design initiatives [16] [17] [18]. Within each category, the proposals are ranked.

Individual items are presented with the author's ranking assessment in the format (importance or value; difficulty or cost) with high (H), medium (M), and low (L) estimates. These estimates are subject to future review by later project participants. [H, L] items are quick wins or low-hanging fruit. [H, M] items are worthy of early attention. A suggested ranking summary of the highest-rated choices appears in Section 5.8.

5.1. Improvements to Existing Designs

1. Conduct an industry workshop to identify agreed needs and opportunities. [H, L]
    a. Collect and rank industry inputs from utilities, key users, and manufacturers.
    b. Develop a roadmap for development beyond what the industry is currently doing.
    c. Components of transformers, protectors, relays, ITs, switching devices, fuses, enclosures, grounding, materials, water and dust vulnerability, maintenance access.
    d. Modeling for SCADA, DERMS, ADMS, specifics of DER integration, system response to events and control sequences, and wide-area protection coordination down to LV network is a key topic of its own, linked to new research topic addition at the end. This might deserve a workshop. [H, L]
2. Condition monitoring additions for protectors and breakers. [H, L]
3. Compact new MV breakers for vault installation. [M, H]
4. Capabilities of controllable electronic fuses. [M, M]

5.2. Scheme Additions (Retrofittable)

1. Compact instrument transformer technologies. [M, M]
    a. Technologies exist; adaptation is the effort.
    b. Optical VTs are available and fill Con Edison's perceived gap more than CTs that serve protection zones.
    c. Precede this work with use case ranking from a workshop or further utility discussions.
2. Study of distance relaying function looking from LV network supply back into transformer. [M, M]
    a. Con Edison reduced priority of transformer fault detection. They cut transformer faults. Oncor and others take transformer failures as a continuing and serious risk.
    b. Development effort can be lower if the project pursues 3-phase modeling of the system.
    c. Function is a component of an integrated design architecture and specification if pursued.
3. Compatible relays for 87 current differential protection zones. [M, M]
    a. Not only transformer fault detection—might include some LV network.
    b. Function is a component of an integrated design architecture and specification if pursued.
    c. May need more CTs.
4. Arc flash sensing by optical or IR/heat, smoke, CO detection means. [H, M]
    a. Can advance the effectiveness of LV smoking fault detection—a serious problem.

   b. The industry has already worked on this, and some solutions are deployed. Can we do better?
   c. There are industry applications of optical-fiber arc flash sensing and relays developed for switchgear that work well and are easy to install in transformer vaults and LV network bus areas.
5. Communicating ground fault detection CTs for LV differential schemes. [H, M]
   a. Aims at LV smoking faults and neutral connection problems possibly tied to stray hazard voltages.
6. Low-cost SCADA communications technology to be developed according to the sequence of 4.7.2 (6).
   a. Specs for use cases, brainstorm/investigate solutions, select trials. Just this part is easy.
   b. This has been well studied by users. We need to bring new methods. Development may be costly.
   c. Cellular data service may be an attractive solution now available in many locations.
7. Integrated redundant protective relaying and control with IEC 61850 communications and optical fibers—water and environmental resistance. [H, H]
   a. This can be part of the overall integration study recommended below.
8. Fast MV ground shunt switch for fault shorting and transfer tripping. [M, H]
   a. Aimed at arc flash reduction and fast clearing but transformer faults are less frequent.
   b. Some users are unwilling to resurrect the practice of transfer tripping by applying a ground fault.
9. As in Section 4.5.2 (8) and (9), electrical predictive apparatus monitoring signatures are conductive and emitted. [H, H]
   a. Opportunity to detect LV and MV low-current and incipient faults, pre-fault degradations.
   b. Focus on security as well as sensitivity (see next).
10. A new study of arcing fault signature analysis prospects, using recent utility feeder trials and experience as applicable. [M, M]
    a. Related utility distribution arcing-fault product testing to date shows that security/false response is a challenge for that signature or pattern detection technology.
    b. Utilities using power quality meters on distribution circuits have reported helpful experience detecting failing apparatus on the circuit before a fault. Applicability to LV network degradations is a research topic.

5.3. Integrated Inverter Control and Protection Capabilities

1. A full array of protection and monitoring functional improvements, including DER monitoring and control features and capability of LV network operation with outflow to utility. [H, M]
2. Power-electronic LV network interface architecture with integrated DER and BESS connection capability. [M, L]
   a. Begin with physical layout prospects when functionalities are combined this way.
   b. Carry out a design study to determine or demonstrate practicality.
3. Inverter control measurements and algorithms to align output with operating circumstances of the LV network and avoid excessive backfeed risk. [M, L]

4. Integration of inverter controls with LV network protection schemes to block outfeed to faults while allowing backfeed to the substation and maximizing ride-through for remote faults and disturbances.
5. Incorporation of islanding detection and microgrid operating mode in the integrated fault protection-inverter control scheme. [19]
6. All of the above are part of the holistic specification of system functional design for LV network-integrated P&C system specification effort. [H, M]
7. All of the above are supported by model development and testing proposed below.

5.4. Other New System Design Initiatives

1. Unified redundant protective relaying schemes with IEC 61850 communications. [H, M]
2. Water and environmental resistance and packaging. [M, H]
3. Complete self-monitoring of P&C systems integrated with power apparatus monitoring and LV network state analysis (consistency of measurements and status indications). [H, M]
4. Combine the above architecture, design, and functional requirements in a holistic:
   a. Integrated P&C specification. [H, M]
   b. Development and demonstration. [H, H]
   c. The model platform of (5.6) below is valuable for development and demonstration.
5. Review of DER modeling accuracy or gaps in widely used tools to analyze protection coordination as discussed in Subsection 4.10.2 (5).
   a. This is a component of a holistic modeling and study platform project (see Subsection 5.6).
6. Investigation for detection of stray voltage hazards. [H, M]
   a. Development of new stray voltage detection techniques. [H, H]

5.5. Selected Additional Opportunities from Consolidated Edison Interviews

1. LV network customer site sensor and evidence processing into actionable binary alarms with minimal false indications.
2. Safe and practical methods and limits for detection of stray voltage hazards on objects in the vicinity of LV distribution system infrastructure, such as utility access hole covers.
3. Collection of a complete set of use cases or application scenarios, with documentation of holistic logic solutions and implementations, to achieve Con Edison and industry objectives for reliable service in combination with minimized site visit and maintenance activities.
4. Investigation of the performance of cathodic protection of transformer tanks against corrosion. Sometimes the anode has disintegrated. Can we measure current or use some other means of alarming if corrosion protection is not working?

5.6. Software Tool and Real-Time Distribution Simulation Modeling with LV Networks

1. Investigate arrays of tools for various study purposes [H, M]
   a. 3-phase protection coordination – CYME, SKM, etc.
   b. 3-phase transient simulation – P&C product off-line algorithm (PSCAD; EMTP) and real-time performance (RTDS) testing.
   c. Relationship to positive-sequence models for load flow, DER impacts, DERMS testing, volt-var optimization (VVO), wide-area control, etc.

2. Investigate modeling gaps and deficiencies and develop solutions. [H, M]
    a. Inverters and integrated controllers.
    b. Control and protection devices.
3. Develop an updated 3-phase real-time model and validate.
    a. Network with DER and conventional loads.
    b. Variety of steady-state and switching or change simulations.
    c. Faults and failures.
    d. Test available P&C products; validate models.
    e. Standard testing platform for new products and systems.
4. Map modeling discoveries to recommendations for widely used tools. [H, M]

5.7. Operational Management Tools for Distribution with LV Networks

1. Investigate arrays of tools for operating purposes related to distribution, including LV networks [H, M]:
    a. SCADA/EMS
    b. DERMS
    c. ADMS
    d. Voltage and load profiles
    e. Data sources, sensing, and control – circuit device comms, sensors, customer devices
    f. Ties to enterprise systems like AMI, GIS, and OMS
    g. Modeling, in conjunction with Topic 5.6.
2. Investigate gaps and deficiencies and propose solutions. [H, M]
    a. Propose demonstration of new features integration via ranking of effort versus benefit and need.
3. Carry out selected demonstration integrations and additions. [H, H]

5.8. Suggested Ranking of Development Opportunities

1. Modeling and operational software and function workshop. [H, L]
2. Overall LV network operation and protection needs and opportunities workshop. [H, L]
3. Study, specify, demo [H, M], then develop software tool and real-time distribution simulation modeling with LV networks.
4. Study, specify, demonstrate [H, M], and then develop [H, H] operational management tool integration for distribution with LV networks.
5. Develop integrated P&C specification - holistic architecture, design, and functional requirements:
    a. Function list with high-level specifications; external data sharing requirements; top-level architecture for an integrated, standardized P-C-M system based on IEC 61850 and ethernet services. [H, M]
    b. Development and demonstration [H, H]; model platform of (2) is important.
6. Electrical predictive apparatus monitoring signatures as in Section 4.5.2 (8) and (9). [H, M]
7. Communicating ground fault detection CTs for LV differential schemes. [H, M]
8. Low-cost SCADA communications technology. [H, H]

9. Arc flash sensing by optical, IR/heat, smoke, CO detection means. [H, M]
10. Investigation of stray voltage detection methods. [H, H]

6. CONCLUSIONS

LV secondary networks are today, and will continue to be, a widely-used technique for providing very high continuity of electric power service to critical loads, especially in dense downtown areas (grid networks) and for critical facilities (spot networks). With growing numbers of smart grid technologies, such as distributed solar PV, electric vehicles, and microgrids, downtown low-voltage networks are going to continue to face challenges expanding on aging infrastructure. Based on existing literature of protecting low-voltage secondary networks and the interviews provided in this report, several key areas of opportunities for technical advancement are proposed. This includes improvements to vault, network, and protector designs, transformer protection, instrument transformers for protection and control, fault clearing methods, LV network electrical fault-sensing methods, non-electrical fault sensing methods, communication opportunities, condition monitoring of protectors and circuit breakers, condition monitoring of protection systems, and steady-state operation of LV network with DER. Five key areas of technical opportunity were identified as:

1.) Increasing demands for fault energy and arc flash reduction, along with reduced tolerance for rare but threatening uncleared faults and resulting burndown events
2.) Introducing DER in customer and utility portions of the distribution grid, which can alter legacy unidirectional power flow assumptions
3.) Advancing the measurement and logic capabilities of microprocessor-based relays
4.) Evolving communications technology to support fault protection, monitoring, and control for new operational demands
5.) Evolving concepts of P&C system integration and monitoring to assure continuous operation while reducing maintenance testing.

The research recommendations have been assessed based on their importance or value and their difficulty or cost. Further development and testing of LV network P&C, with its MV supply systems, depends on modeling tools which in turn can benefit from new development, both for accuracy of modeling existing components and for the ability to properly model the behavior of new components like inverter-based DER in normal operations and fault or switching conditions. A suggested ranking summary of the highest-rated choices appears in Section 5.8. There are hundreds of downtown low-voltage grid and spot networks in the United States, so it is critically important to address these challenges to improve protection of secondary networks for access to clean energy and continued reliability.

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