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TRANSFORMER TECHNOLOGY^{MAG}

NEW DESIGN AND ADVANCES IN TECHNOLOGY

Digital Twins: **Revolutionizing Testing of Protection Relays**
Power Cable Systems **Reliability and Longevity**: Past, Present, and the Future
Cost Effective **Methods for Repairing Oil and Gas Leaks**

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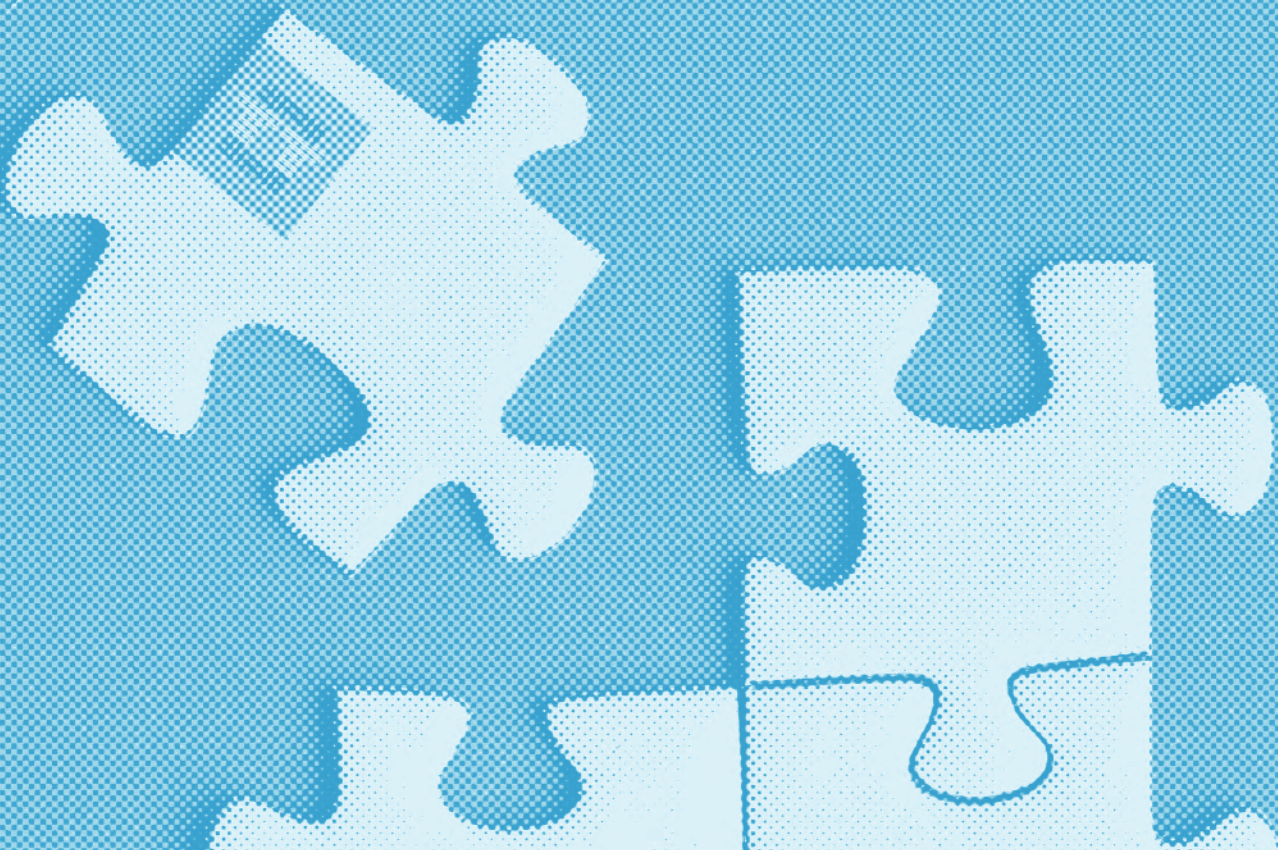
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Index



Table of Contents_	04
Editors & Impressum_	10
Editor's Letter_	12
Digital Twins: Revolutionizing Testing of Protection Relays_	14
Cancel Your Subscription to Electrical Safety Issues_	22
Electric Substation Large Power Equipment: Cost Effective Methods for Repairing Oil and Gas Leaks_	30
TMC @ IEEE T&D Exhibition: Network Transformers on Stage_	38
Grid Innovations and Digital Transformation_	40

Contents

Table of

14

Digital Twins: Revolutionizing Testing of Protection Relays

The digital twin concept has been taken a step further with the development of a cloud-based digital twin of protection devices. This article discusses benefits of this technology when applied in the relay protection engineering and testing world.



22

Cancel Your Subscription to Electrical Safety Issues

Recent statistics show there is a severe lack of safety in the electrical world that results in an incredible amount of injuries, fatalities, and cost. The most effective way to achieve success in protecting electrical workers, assets, and operations, is to follow a Problem → Action → Solution approach. This article brings an overview of these steps.



30

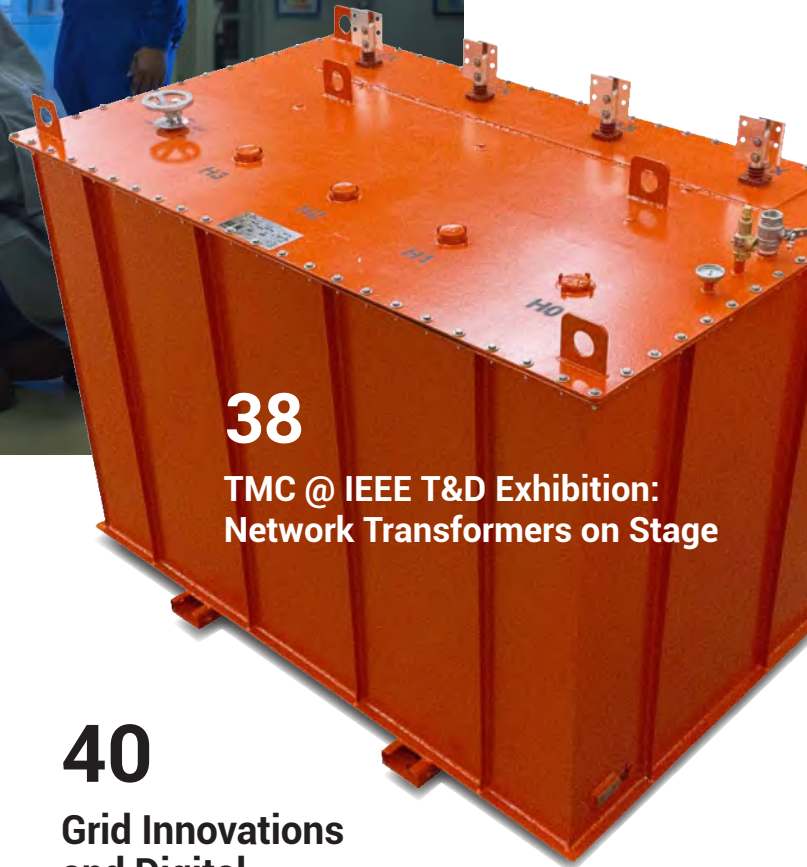
Electric Substation Large Power Equipment: Cost Effective Methods for Repairing Oil and Gas Leaks

Many transformers still in service today were built in the slide-rule era designed by engineers with a built-to-last mentality. Although they were built to last, they have their share of old age issues coming to bear. One of the greatest issues is oil leaks. This article presents cost effective methods for repairing oil and gas leaks.



38

TMC @ IEEE T&D Exhibition: Network Transformers on Stage



40

Grid Innovations and Digital Transformation

This article discusses four grid technological innovations that are changing the way power substations work and giving grid operators the ability to better manage those substations and the network as a whole—paving the way to meet changing energy demands.



Index



Power Cable Systems Reliability
and Longevity: Past, Present, and
the Future_**54**

Technical Advisors' Column:
Control Transformers_**64**

Women of Note: Efra Farah
Usmani_**69**

How Crucial is HVDC for Energy
Transition? Landscape of HVDC
Technology in North America and
Europe_**70**

Transformer Connections: Types
and Their Impact on System
Performance_**78**

Coming in April_**88**

Contents

54

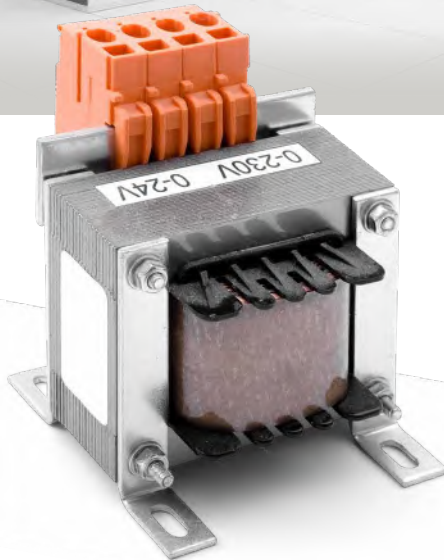
Power Cable Systems Reliability and Longevity: Past, Present, and the Future

Medium and high voltage cable systems are one of the most commonly overlooked power system assets and yet they are the arteries enabling reliable grid operation. This article takes a step back to promote knowledge sharing and industry best practices by reviewing the past and the present, providing a vision for reliability and longevity beyond 100 years of service life.



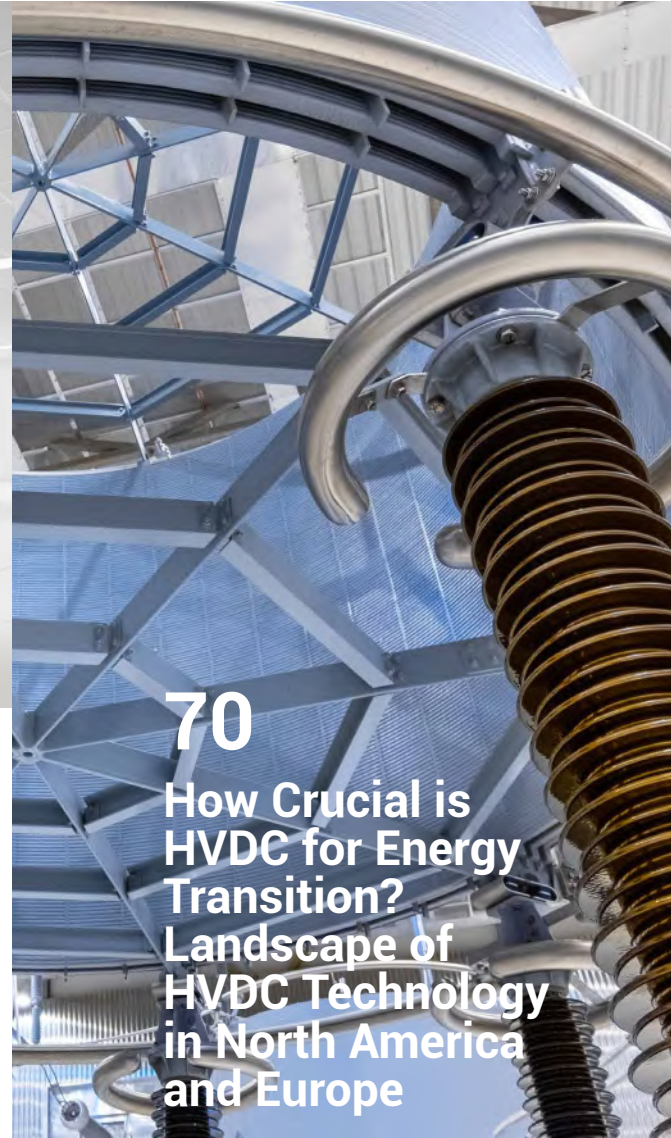
64

Technical Advisors' Column: Control Transformers



70

How Crucial is HVDC for Energy Transition? Landscape of HVDC Technology in North America and Europe



There are more than 350 installed and upcoming HVDC projects globally, with the largest number of them being in APAC, followed by Europe and North America. This article focuses on two of these regions: North America and Europe.

78

Transformer Connections: Types and Their Impact on System Performance

What is the impact of transformer connections and the type of neutral grounding on system performance? Find out in this article.



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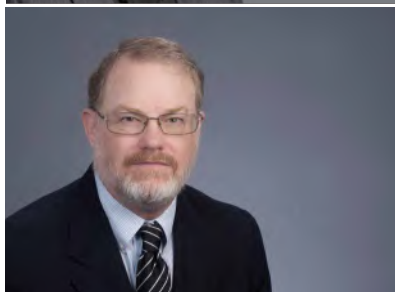
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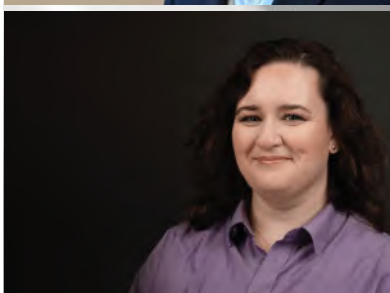
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Dear Readers,

I am most thankful that in trying times like these, we still manage to focus on our tasks at hand, the daily things that keep life on track. In the power industry we must do that, or the lights don't shine, the factories shut down and normal life as we know it comes to a halt. In the media industry, that means we need a continuous flow of great content to share with each other in the Transformer Technology community. Once again, our authors, interviewees and staff came through.

It is especially gratifying because we stretched our wings a bit this month, by adding content outside the direct realm of transformers and we did it for a reason. In June and beyond, we will be adding another aspect to our community, Power Systems Technology. While the heart of the system is the transformer, there is so much more to the power system that we will begin to address. This issue is merely the beginning. While we will always stay true to our roots, Transformer Technology, we will also focus on those components of the system that are impacted by or have an impact on transformers.



In June and beyond, we will be adding another aspect to our community, Power Systems Technology.

If I could go back to university and change my major, it would be to become a Systems Engineer rather than a mechanical one. Why? Because the system that an asset is in is much more important than any one asset within that system, and as assets become more complex, more solid state than electromechanical, then looking at the whole is often the best way to understand the impact any one asset has on the overall results produced by the system. In the case of electrical systems, that result is safe, clean, cost effective and quality power.

Add to the fact that a resilient or reliable grid requires that we consider every part of that grid to work together to accomplish the desired result. Speaking of reliability, the past few decades of work in the power reliability world has taught me that all reliability begins with design. The design of the system and the assets that make up that system. Unfortunately, we seldom get to design brand new systems, hopefully something that is changing globally as economies look to rebuild infrastructure. Usually, we must upgrade existing systems by adding new technology and new assets into an older existing system. That is why we bring Power Systems Technology thinking and content to our community. Given that transformers are usually the oldest part of an existing system, the addition of a lot of newer technology means we must expect there to be an impact either on the high side or low side of the transformer.





Change can be challenging. It usually is. But it can also be exciting, as we believe it is in our industry. Join us as we begin to address how technology can and will impact these changes for building new grids and updating existing ones.

Also, the rapid increase in the use of monitoring systems and advances in transformer component design means we need to expand our thinking when it comes to the heart of the system - transformers.

Change can be challenging. It usually is. But it can also be exciting, as we believe it is in our industry. The rapid decline in the use of coal, at least in Europe and North America, the reluctance to build nuclear power generation, the need for vastly more power to support the electrification of transportation and the response to global climate change are all going to impact the rate of change within the power system. Join us as we begin to address how technology can and will impact these changes for building new grids and updating existing ones.

Alan M Ross
CRL, CMRP
Editor in Chief
Transformer Technology
Curator of the Community
President of EPRA



Alan M Ross



Digital Twins: Revolutionizing Testing of Protection Relays

by **Niclas Wetterstrand**
and **Andrea Bonetti**



Simulating an asset's physical or functional performance in a computer – a digital twin – has delivered benefits in engineering for decades.



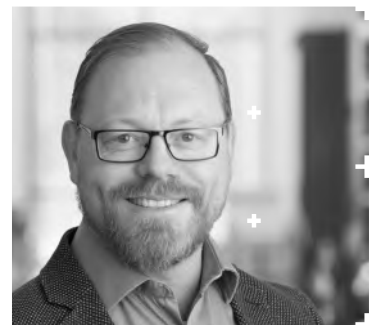
There are now companies who have developed and are enabling this technology in the relay protection engineering and testing world.



This has allowed companies to continue carrying out a range of tasks despite the travel bans and social distancing measures that have arisen during the COVID-19 pandemic.



Beyond that, benefits like cost savings, work force utilization, comfortable working hours, and trained personnel, are being achieved.



Niclas Wetterstrand has in his whole career been working with electrical test equipment for the Power Sector. He started with Megger Sweden (formerly PROGRAMMA) in 1992 and have been in various roles such as Production Management, Quality, Commercial Marketing, Strategic Marketing, Product Management and Sales. Niclas is currently a Business Development Director (BDD) for protection at Megger group and is responsible for the strategic planning of Megger test equipment within relay protection, circuit breaker, instrument transformer and primary testing. Niclas is a Cigré member and is a frequent speaker at international conferences.



Andrea Bonetti is Senior Specialist in power system protection and IEC 61850 applications at MEGGER SWEDEN AB. Prior to that he worked as product manager and technical specialist for relay test equipment and IEC 61850 test set and tools at Megger for 7 years, and has 18 years of experience as HV power system protection specialist at HV relay protection manufacturer ABB Grid Automation Products. Andrea is member of the IEC TC 95/MT 4 and TC 95/WG 2 committees, and he received the IEC 1906 Award in 2013. He holds a patent in the area of IEC 61850 testing tools and algorithms. Andrea obtained a master of science degree in electrical engineering from Sapienza University of Rome, Italy.

A digital twin is a digital copy of a physical asset. This concept has been used for a long time within the power industry, for instance, when designing the physical layout of a substation. If the digital copy is well made and the creation tool enables the drawings to be generated automatically, the physical build of the substation and its components should fit perfectly together and within the defined footprint, without rework. Simulation of power networks functionality is frequently used to justify designs and calculate relay protection settings. Even functional simulation down to asset level happens today, but that is a generic simulation of a function. The benefit is that the system is proven to work in the digital world, and if the setup in the virtual world is well designed, it is highly likely to work in the real world.

Today, this concept has been taken one step further with the development of a cloud-based digital twin of protection devices. The relay protection functions in the digital twin have been cloned from the physical asset so the behaviour is identical. User interfaces like the front panel buttons and display are the same and the configuration software is used as one would do with a physical relay. The environment also allows a system of digital twin IEDs to be connected so a larger installation can be set up virtually. This opens new possibilities since the relay setup can be tested in every degree; but to do that, a way to simulate the electrical properties of the power network virtually is needed.

A digital twin of a test equipment is doing exactly that. Instead of generating voltages and currents as the physical product would do, its digital twin is providing these signals digitally. With this test setup, when the digital twins of both the protection relay and test set interoperate, it is possible to evaluate

DIGITAL TWIN TECHNOLOGY SIMULATES AN ASSET'S PHYSICAL OR FUNCTIONAL PERFORMANCE.

This unlocks enormous potential to perform a lot of test activities virtually instead of relying on the traditional way with physical assets.

Remote FAT

Factory acceptance testing (FAT) is normally performed at the supplier's or contractor's site to ensure that the selected components both are configured properly and work together in the way that the system was designed. This means that all equipment needs to be sent to the same location and installed and wired temporarily, which is both costly and time consuming. This is still viewed as a time saving and important step since it proves that the system works as designed. Plus, when problems arise, and they always do, the project team can troubleshoot in a controlled environment and during a less stressful project phase than that of the actual commissioning. Furthermore, the technical experts are either involved to support this activity or at least physically nearby, so it is easier to get their support than when being out in the field.

The digital twin environment creates notable advantages in the context of FAT. The process of setting up the system with digital twins, the so-called "digital twin ecosystem", requires a small effort but saves time and a notable net cost over the use

of real assets. These savings are achieved because the need for transportation and temporary wiring are eliminated. To create the digital twin ecosystem, simply select the required assets in the digital twin system and

THE CONCEPT OF THE DIGITAL TWIN HAS BEEN TAKEN A STEP FURTHER WITH THE DEVELOPMENT OF A CLOUD-BASED DIGITAL TWIN OF PROTECTION DEVICES, OPENING UP NEW POSSIBILITIES IN THE RELAY PROTECTION ENGINEERING AND TESTING WORLD.



digitally connect them with a few clicks. Once it is set up, this system can be accessed and worked upon by many engineers in parallel, which gives opportunities to reduce the lead time.

In addition, these engineers can comfortably work from their desk during their normal work hours instead of travelling to the FAT site. If they need to be at a different location, engineers can access the digital twin wherever they are in the world, if they have access to internet. Virtual FAT with digital twins has been extremely valuable during the pandemic where travel bans, and social distancing have been imposed.

Commissioning

The benefits don't end with the validation of the protection system design. A subset of the tests that were created in the digital twin for the

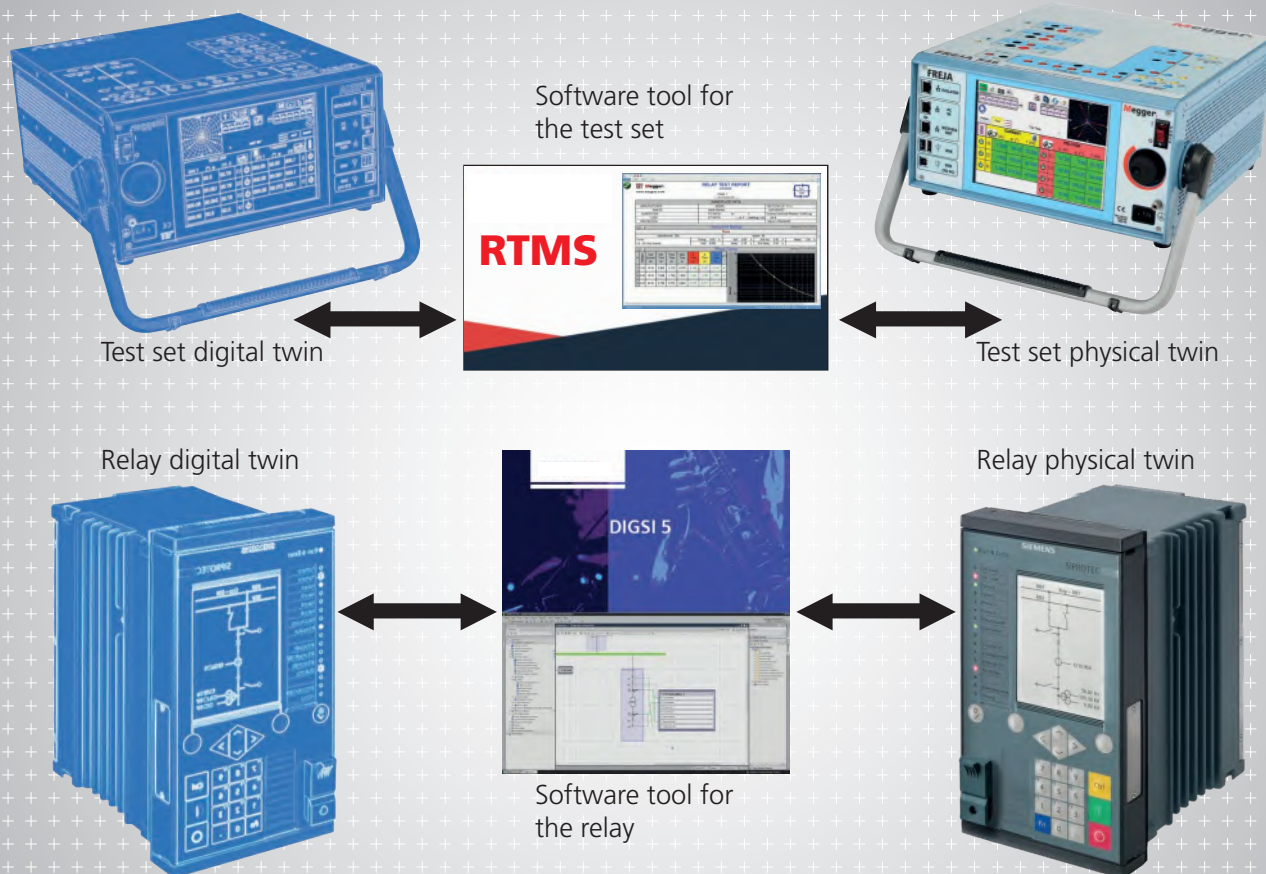
test system can be reused later when arriving at the site. This saves time in the time critical commissioning phase. This also gives the commission engineer confidence that the system has worked before so the troubleshooting of problems that arise in this stage can be focused on hardware and connection issues. Furthermore, the digital twin system should be saved for future use in training, remote support, or when validating ensuing upgrades.

"But wait a minute", say the professionals, "we didn't capture any tests of the hardware and the physical connections?"

Yes, this is true, and this cannot be skipped before the system is put in service. Then the question becomes:

WHEN THE DIGITAL TWINS OF BOTH THE PROTECTION RELAY AND TEST SET INTEROPERATE, IT IS POSSIBLE TO EVALUATE THE VIRTUAL PROTECTION RELAY FUNCTIONS WITH SO CALLED "VIRTUAL TESTING". THIS UNLOCKS ENORMOUS POTENTIAL TO PERFORM A LOT OF TEST ACTIVITIES VIRTUALLY INSTEAD OF RELYING ON THE TRADITIONAL WAY WITH PHYSICAL ASSETS.

How many times do we need to test the hardware before it is placed into service? It is already done in the factory when the asset passes its final quality assurance test; can we rely on that? To fully benefit the virtual FAT, the answer is yes. The hardware tests performed in the FAT are then moved



Validated relay files can be re-used in the substation

Validated test-set files can be re-used in the substation

t o the site and taken care of in the commissioning phase.

The key factor for a successful virtual commissioning, and a subsequent site commissioning, is the reusability of the data between the digital twins and the physical twins. Put differently, the digital twin and its physical twin must be able to share the same data.

With this data sharing approach, the test files that were validated during the virtual tests, where digital twins were used, can be reused by the physical twin test set. The same is true of the relay protection

data (settings, configuration etc...): the setting file validated during the virtual tests can be transferred to the

physical twin, minimising the risk of mistakes, increasing the quality of the delivered protection system, and contributing to great time savings.

Training

Wouldn't it be wonderful if there was a possibility to get familiarised with the substation that's going to be commissioned

beforehand? Well, you guessed it, with the digital twin this is possible. Personnel can get training not only on the actual IEDs used in this project but also on the system where the IEDs are working together. Training after completion of the virtual FAT is possible as the test equipment and the prepared test files used for this FAT are available. This preparation gives greater confidence that the commissioning will go according to plan and minimises the risk of being caught off-guard by something unexpected.

For junior engineers, this is even more valuable since experience can be built in a comfortable home environment where mistakes aren't hazardous or costly, as they don't involve live voltages and hardware that can be damaged. Plus, expert guidance and support is nearby. As with the FAT, the training can also be performed in parallel, where all students have

THE DIGITAL TWIN TECHNOLOGY CAN PLAY AN IMPORTANT ROLE IN THE SUBSTATION LIFE CYCLE IN THE EVENT OF AN UPGRADE – FOR THE CONFIRMATION OF HOW THE REPLACED IEDS WILL OPERATE IN THE OLD ENVIRONMENT, FOR TESTING THE SUBSTATION EXPANSION DESIGN, AND FOR HOW THE NEW SECTION WILL WORK WITH THE OLD.

Are the settings wrong?

Am I using the correct test method?

Is the relay working well

access to all parts of the system at the same time, and they all have their own digital twin of the test equipment to work with. This is very different from how training with physical assets is performed, wherein a group typically has access to a limited number of relays and test equipment.

Remote support during commissioning

Commissioning is normally the last phase before the substation is

put in service to start generating revenue. Therefore, there is normally high pressure to deliver the project on time. Mistakes and problems get high visibility and might affect the delivery date, and solving problems, under pressured time, is in many cases notably inefficient. To enter this phase with a system that

THE ABILITIES OF
DIGITAL TWINS CAN
OFFER SIGNIFICANT
HELP WITH RESEARCH
AND DEVELOPMENT,
CHALLENGING TEST TASKS
WITH GREAT DISTANCES
BETWEEN IEDS, OR
SITUATIONS WHERE A
SUPER-TEST SET WOULD
BE NEEDED.

has already been tested virtually, with the test files already created, and the engineers trained, is a great step forward. However, all who have been part of a commission-

Should I
escalate the issue?

What if I do nothing?



... I wish to have one
second opinion...

ing job know that there are always some uncertainties, which may lead to problems that need to be solved on the fly. Typical questions from commissioning engineers, experiencing doubts, are:

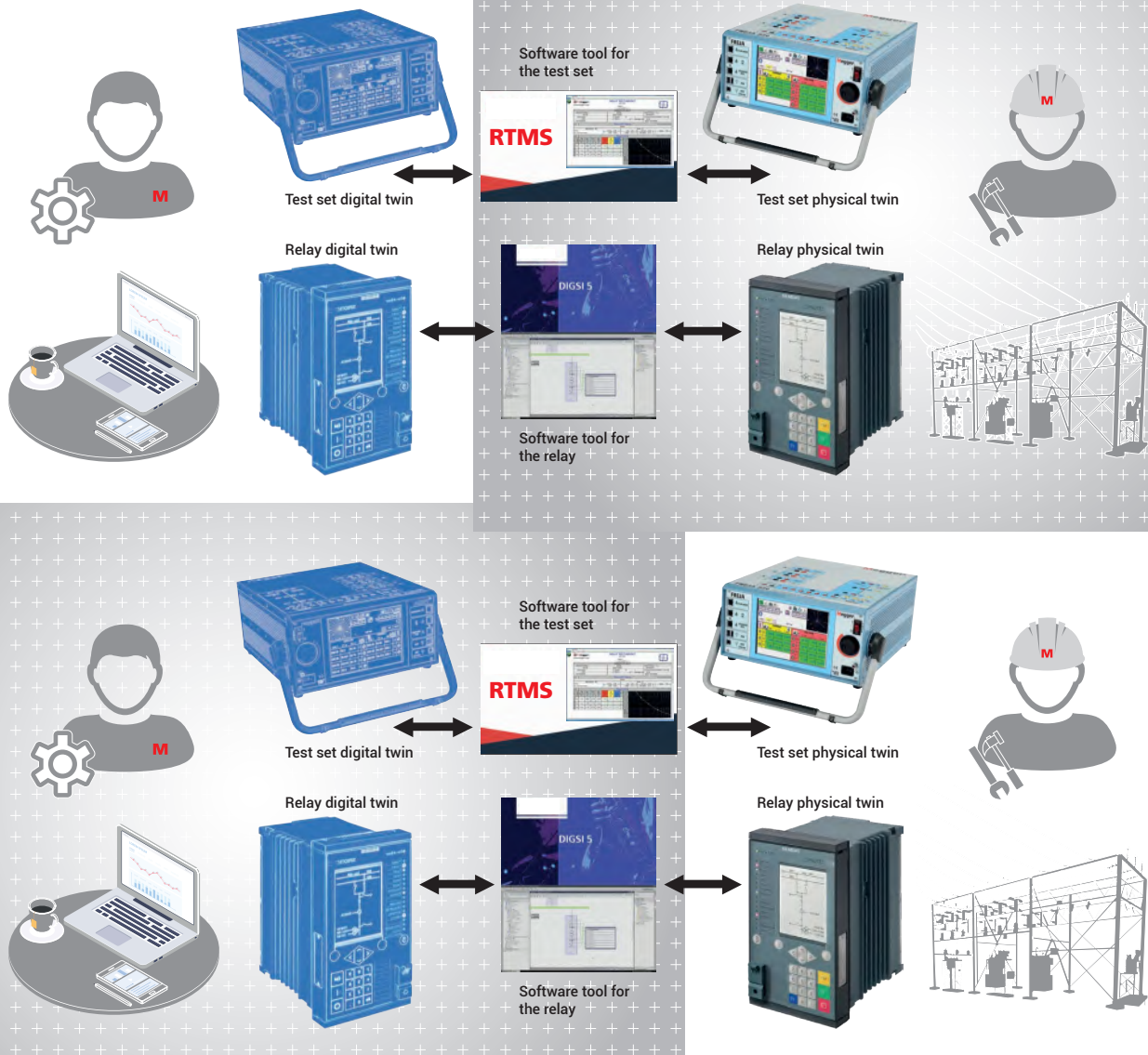
- Is the relay performing correctly?
- Am I using the correct testing method?
- Should I escalate this issue?
- What happens if I do not escalate it?
- Who can help me with a good 'second opinion'?

Navigating these nagging concerns is all in a day's work for commissioning engineers, and they do it very well. However, sometimes even these talented people get stuck, or at least like to get a second opinion to ensure their proposed solution is appropriate. This is where the digital twin again provides a huge benefit.

A problem discovered during commissioning can easily be replicated so that more experienced experts back in the factory both, can

see the problem for themselves, and propose a definitive working solution. The actual setting files and testing files from the field are read from the physical devices and are sent to the expert who loads the received data into the digital twins and can start troubleshooting.

When the problem is found and corrected, an updated settings file with corresponding updated tests are returned to the commissioning engineer. These files are now reused



and tested in the field to make sure the problem is solved, even though the likelihood is high that the problem is solved, since it has already been confirmed with the digital twin. The digital twin technology enables the technical expert to be present when needed, without travel or disruption to normal working hours. The technology also allows high level specialists to be present on test activities that are too demanding for average technicians. This way the specialists can contribute to decreased mistakes during on-site commissioning testing.

Firmware or hardware updates

Finally, the digital twin technology can play an important role in the substation life cycle in the event of an upgrade. This may range from a small firmware upgrade to something larger, such as an upgrade of several IEDs or extending the substation capability. In the example of a firmware upgrade, the

substation owner wants to make sure that this upgrade will not affect the IED protection capabilities. By making a few successful tests in the digital twin environment, the substation owner confirms that the firmware upgrade will not cause an unexpected interruption, or worse, insufficient protection of the network assets. This will ease the minds of both the one responsible from the supplier and the substation owner.

Major upgrades to an existing system, such as multiple IED replacements or a substation expansion, are rather commonplace since many power grids were built a long time ago, and have capabilities that are reaching their limits with today's increased demands for electrical supply. These projects are like new installations, but the new parts need to work with the old installation, therefore the digital twin is beneficial for the confirmation of how the replaced IEDs will operate in the old

environment, for testing the substation expansion design, and for how the new section will work with the old.

Conclusion

The digital twin technology exceeds what standard simulation tools can perform today. To have an exact functional digital copy of the IEDs and the test equipment that also can interact with each other has proven to provide benefits in the areas highlighted in this article – FAT, Training, Commissioning, and Upgrading – and it doesn't stop there! The abilities of digital twins can offer significant help with research and development, challenging test tasks with great distances between IEDs, or situations where a super-test set would be needed. The digital twin marks a new era of substation verification and will drive increased quality and reduced costs for the delivered protection systems.

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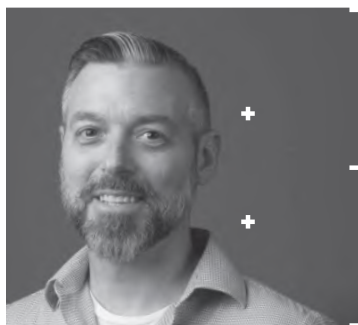
Cancel Your Subscription to Electrical Safety Issues

by **Michael Riccio**

+++++

The review of statistics blatantly demonstrates there is a severe lack of safety in the electrical world that results in an incredible amount of injuries, fatalities, and cost.

Problem solving is a skill we are all taught from a very young age, and as we mature it becomes more and more of a life requirement, not just as individuals, but as teams, organizations and markets/industries. The electrical world, like most other industries, should be focused first on avoiding problems and then solving any if they arise. That comes down to proper program design, where protection systems and policies are put in place to prevent worker injuries/fatalities, equipment/operational downtime, and lost revenue.



Michael Riccio, CRL, IRT CAT-1, is the Global Marketing Manager for IRISS Group, providing market/industry analysis, support, and educational insights to customers, distributors, and sales worldwide. He is a Certified Reliability Leader, a CAT-1 IRT thermographer, and is a contributing writer to other industry publications such as the National Safety Council's *Health & Safety Magazine*, *Food & Drink Processing & Packaging*, and *Process Engineering Control & Manufacturing (UK)*.

ELECTRICAL
SAFETY

As noted in the previous article, [Tragedy & Expense: The High Cost of Low Electrical Safety Standards](#), the industry continually falls short of enacting effective protection systems and annually makes OSHA's "Top Ten" for these failures. As much effort as the industry puts into developing and adhering to programs that meet governing bodies' standards, the numbers show failure in worker protection.

According to the Bureau of Labor Statistics (BLS), electrocution is the fifth leading cause of workplace fatalities in the United States. Within the electrical industry where workers are exposed to this possible hazard



daily, this might seem like a basic fact. From a wider perspective, however, the number is surprisingly high when we consider how few people in the overall American workforce perform “electrical-related work” as part of their standard job duties.

Another concern to take note of is that electrical shock is the second leading cause for lost time on the job in the electrical world. Every thirty minutes during the workday, as reported by the Electrical Safety Foundation International, a worker suffers an electrical-induced injury that requires time off the job. Their study further found that 97% of

electricians have been shocked or injured on the job. Arc flash fatalities are not counted in this statistic; they are logged under burn injuries, meaning that the rates are even higher. One of OSHA's recent reports show that 80% of electrical-related accidents and fatalities involving “Qualified Workers” are caused by Arc Flash or Arc Blast.

2,000 workers are treated in specialized burn trauma centers each year from arc flash injuries. These high-tech facilities only treat the most devastated burn victims – those who have sustained incurable third-degree burns over more than half of their body.

According to the Bureau of Labor Statistics (BLS), electrocution is the fifth leading cause of workplace fatalities in the United States.

To put the severity of burns into perspective, BLS reports that 60% of workplace fatalities are caused by burn injuries. Arc flash injuries are much higher than reported because workers receiving treatment for trauma and burns that do not require burn unit attention (*i.e.*, second-degree burns or third-degree burns covering less than half their body) are admitted to standard hospitals which do not track the burn source.

The number one killer of IBEW (International Brotherhood of Electrical Workers) trained electricians (admittedly the safest trained electricians overall) is shock and/or falling when changing a 277 V lighting ballast. This is a common task and often the fatality is recorded as a fall death or a heart attack, and not as an electrical incident. However, doctors, OSHA and company officials are becoming aware of the true cause of the fatality. A new part of the NEC prevents this type of incident from occurring by requiring the addition of a disconnect at every lighting ballast on 277 V lighting.

Equipment reliability, along with protection systems, is key to creating a safe and effective operation. Field tests and surveys have shown that 22% of breakers operate at less than 100% efficiency (slow trip), and more than 10% have been shown not to open at all. Even the slightest delay in the operation of a breaker or fuse, will double or triple the available incident energy in an arc flash event.

More accidents occur with 480 V equipment than on higher voltage equipment. Incident numbers with 480 V equipment is often higher than in higher voltage equipment due to the increased current and higher clearing time in these applications

when compared to higher voltage applications.

Incident energy calculations, and therefore PPE selection, are based on equipment that is "properly installed and properly maintained". Most manufacturers recommend exercising breakers at least once per year to lubricate the inner working of the breaker mechanisms [1].

Recent reports show that 97% of electricians have been shocked or injured on the job.

The Keys to Driving Safety

The most effective way to achieve success in protecting electrical workers, assets, and operations, is to follow a *Problem → Action → Solution* approach. The above review of statistics blatantly demonstrate that the Problem is a severe lack of safety in the electrical world that results in an incredible amount of injuries, fatalities, and cost. The next step is to analyze the *Actions* that are causing these problems, or as the electrical world refers to it, do a *Root Cause Analysis* to identify hazards. Once those issues have been identified, the *Solution* is simply to fix them by designing a system that both eliminates them presently and prevents future occurrences. "Simply" is the key, because the solution will only work if the program is designed with enough simplicity that it is teachable, understandable, and repeatable.

What are the Electrical Hazards? The four primary hazards associated with electricity are shock, fire ignition, arc flash and arc blast. Of course, when an electrical incident occurs, other hazards may come into play such as falls from elevated locations and working within a confined space. The results can be direct, such as electrocution, burn injuries, or indirect such as a fall or smoke inhalation. Common conditions that may increase hazards are elevated locations and confined spaces.



The four primary hazards associated with electricity are shock, fire ignition, arc flash and arc blast.

Worksite analysis

Worksite analysis is key to identifying and understanding current risks. Workers and Management should actively analyze the worksite to anticipate and prevent hazards from occurring. This involves identification of all hazards by conducting baseline worksite surveys for safety and health and periodic comprehensive update surveys. Also included would be an analysis of planned and new facilities, processes, materials, and equipment; and another of routine job hazards. Regular site safety and health inspections should be conducted, so that new or previously missed hazards and failures in hazard controls are identified.

Hazard Prevention and Control

Once a hazard or potential hazard has been identified, the next step is to determine how to control or prevent that hazard. When feasible, prevent hazards by effective design of job or job site. Where elimination is not feasible, the action is to control hazards and prevent unsafe and unhealthful exposure. A proper risk assessment should be done during this stage, where risk is compared to the effort required for removal. It is reasonably practicable if a risk can be removed at minimal cost and effort, however it is not reasonably practicable if the cost of removal of risk is disproportionately high.

Asset Management and Design Strategies

The aim of any solution is to provide the "maximum amount of protection" by eliminating or minimizing the exposure or hazard. Elimination and Substitution are the most important levels in NFPA's Hierarchy of Controls, and how you prevent or control a hazard. The main goal for any fix to a hazard or exposure is to eliminate it altogether or substitute a product or method of doing the work to a less hazardous alternative.

A major part of asset design and procurement relies heavily on the input from the Original Equipment Manufacturer (OEM), which significantly impacts the ultimate design, reliability, and success of a project.

Together, Be "Better"

Some may look around their facilities and think they have electrical safety "best practices" well in hand, but the term "best practices" is a flawed concept itself. "Best" denotes a superlative, where the pinnacle has been reached and nothing can be improved. Instead, a focus on "better practices" should be the top-to-bottom standard. Much like industry innovations for production and distribution never settle for status quo, safety practices should also strive towards perfection with the understanding that it will never be reached.

This can be achieved through an "all-hands, top-to-bottom" approach to designing and implementing an effective and adaptable electrical safety and reliability program. Some may argue that too many cooks in the kitchen will spoil the dish, but without 100% commitment from the entire team, no plan will work. The key is to a shared understanding of who is responsible for what, and how everyone's role fits into the bigger picture.

Principles of system design in high availability engineering to be aware of:

1. **Elimination of single points of failure means adding redundancy to the system so that failure of a component does not mean failure of the entire system.**
2. **Reliable crossover. In multi-threaded systems, the crossover point itself tends to become a single point of failure. High availability engineering must provide for reliable crossover.**
3. **Detection of failures as they occur. If the first two principles are observed, then a user may never see a failure. But the maintenance and reliability activities must be designed to detect early signs of impending failure.**

1. As much as 60% of failures & safety issues can be prevented by making changes in design
2. 80% or more of a facility's life cycle cost is fixed during the plan, design, and build phases
3. 30-40% of equipment breakdowns are related to poor equipment design or condition

! CAUTION

**ARC FLASH AND
SHOCK HAZARD**

Appropriate PPE
and Tools Required
When Working on
This Equipment.



Occupational Health & Safety standards are a clear statement as to the general responsibility of both employer and employee:

General duties on the employer

- provide safe place of work
- provide safe plant and equipment
- provide safe systems of work

General duties on the employees

- to take reasonable care
- to co-operate with the employer
- not to interfere with safety arrangements

Management commitment and employee involvement go together. Top management involvement should be visible, with the authority and resources to implement program. Their involvement in implementing the program is crucial so that all employees understand it is a serious commitment. This commitment provides the motivating force and resources for organizing and controlling activities within an

organization and ability to get things done and requires that responsible parties have the necessary authority and equipment, so that assigned responsibilities can be met.

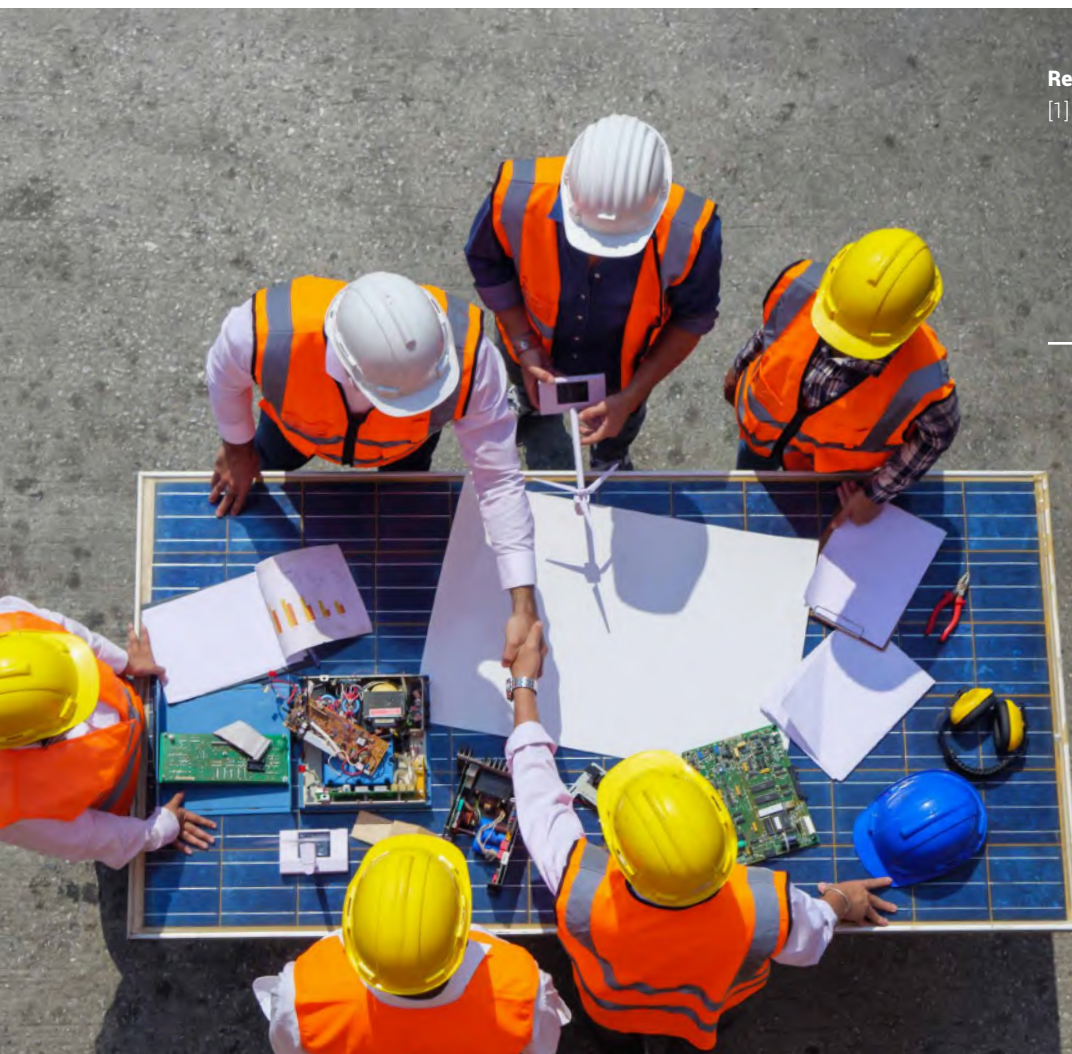
Encouraging employee involvement in the program and in decisions that affect their safety and health (e.g., inspection or hazard analysis teams; developing or revising safe work rules;

training new hires or co-workers; assisting in accident investigations) provides the means through which workers develop and express their own commitment to safety and health protection. Making use of everyone's insight not only creates a synergy among participants, but also a shared sense of ownership that leads to participants holding themselves and each other accountable.

Management commitment and employee involvement go together. Encouraging employee involvement in the program and in decisions that affect their safety and health provides the means through which workers develop and express their own commitment to safety and health protection.

References

- [1] NFPA 70E, Standard for Electrical Safety in the Workplace, accessed here: <https://www.nfpa.org/codes-and-standards/all-codes-and-standards/list-of-codes-and-standards/detail?code=70E>



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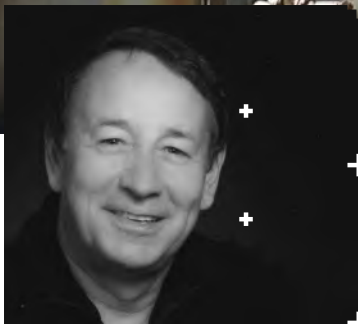
Electric Substation Large Power Equipment: Cost Effective Methods for Repairing Oil and Gas Leaks

by **Steven H. Wickman**

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To keep in tune with the theme of the last edition of *Transformer Technology*, a large, oil-filled power transformer is definitely the heart of the power system. Even with the advances in the technology of other insulating media, the large oil-filled transformer is still the tried-and-true major component of the transmission-type electric substation, as well as the sub-transmission and distribution substations. Many transformers still in service today were built in the slide-rule era designed by engineers with a built-to-last mentality. Thus, there are many older oil-filled transformers still out there throughout the world. Although they were built to last, they have their share of old age issues coming to bear. One of the greatest issues is oil leaks. Gaskets on bushings, radiator flanges, pumps, piping, etc. are deteriorating and leaking.

Many transformers still in service today were built in the slide-rule era designed by engineers with a built-to-last mentality. Although they were built to last, they have their share of old age issues coming to bear, one of the greatest issues being oil leaks.



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Figure 1. Evidence of oil running down the sides of a large power transformer creates a negative perception of the utility's maintenance program.

According to literature, it is not uncommon for a transformer operating at higher temperatures to develop leaks from gasket failure after about 10 to 12 years in service. However, transformers are typically expected to remain in service much longer than this. Thus, sometime during the operating life of the transformer, the unit is going to experience deteriorated gaskets and subsequent oil leaks. If oil is leaking out, there is a risk of moisture and air being drawn in via capillary action, compromising the transformer oil insulating qualities.

The classic repair technique is to regasket the transformer, which entails taking the transformer out of service and draining the oil – usually thousands of gallons, removing radiators, removing bushings, and so on.

All these steps keeping your transformer out of service for weeks, and utilizing large substation crews, cranes, tankers, vacuum fill-oil processing trailers and similar can be a costly endeavor. Today's electric utility management is monitoring expenses closely. Transmission operations are wheeling power from

far-away generation sources to the local utility distribution load centers. Outages on transmission equipment are closely scheduled and lengthy outages are not granted on short notice for emergent repairs. The Operations people are coming to the Maintenance people asking for other solutions to address these oil leak repairs. The U.S. EPA Spill Prevention, Control, and Countermeasure (SPCC) Regulations (40CFR112) contains stringent requirements for electric utilities to monitor their equipment to prevent oil discharges off their substation properties. Even slight oil leaks, creating stains down the sides of transformers and oil circuit breakers, create a negative perception to the general public that the utility is not maintaining their equipment to a high standard of reliability (Figure 1).

There is a viable alternative solution to the oil leak correction problems on electric utility equipment. A technique for replacing failed and leaking gaskets in transformers is available through online leak seal technique.

It is not uncommon for a transformer operating at higher temperatures to develop leaks from gasket failure after about 10 to 12 years in service.

Consistency

Drill and Inject Technique

There are two techniques prevalent amongst the leak-sealing specialists. The first of these is a Drill and Inject technique whereby the leak seal technicians are able to drill access holes to the gasket groove and inject, under pressure, a sealant compound, essentially creating a new gasket without disassembly of the transformer to access the gasket groove (Figure 2).

Then pipe plugs are inserted to contain the sealant under pressure while it cures. The sealant is injected in a fluid, liquid state that has a consistency similar to honey or pancake syrup, to use an easily understood analogy.

The sealant cures into a flexible material that has durometric properties essentially identical to those of OEM nitrile rubber gaskets. The life cycle of the leak seal installed gasket material is essentially the same as OEM gaskets. Thus, with the leak seal repair technique you get the same result as regasketing without all the extra time, labor, and expense of a drain and regasket repair. Additionally, many Drill and Inject repairs, particularly if the leaks being addressed are on piping flanges at the lower end of radiators, away from

the energized components, can be performed with the transformer still in service carrying load (Figure 3).

Online leak seal techniques for replacing failed and leaking gaskets offer a viable alternative solution to regasketing, as they don't require taking the transformer out of service and draining the oil.

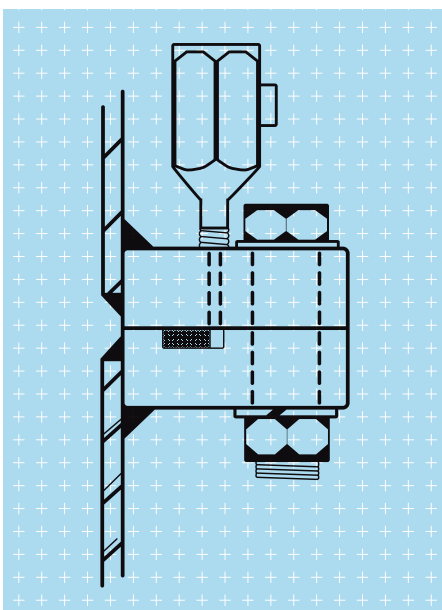


Figure 2. Drill and Inject technique. Left: A graphical sketch depicting how the injection valve is drilled into the gasket groove to inject the liquid sealant material and effectively replace the failed gasket material. Right: Injection valve with sealant injection hose.

Lastly, with this minimally invasive repair technique, it can be a viable option to only address the existing leaking components as opposed to doing a complete drain and regasket of the entire unit.

Some flanges on oil-filled apparatus cannot be repaired by the Drill and Inject technique. Open-faced flanges, where there is not a recessed gasket groove, require an alternative repair technique, which is to apply a custom fabricated aluminum clamp externally around the leaking flange. This clamp, measured and fabricated to the precise dimensions of the flange, is put in place and has an internal groove that is filled with the

same leak seal sealant to create, in essence, an external gasket around the leaking component. This leak repair technique works effectively on virtually any flange that cannot be drilled and injected (Figure 4).

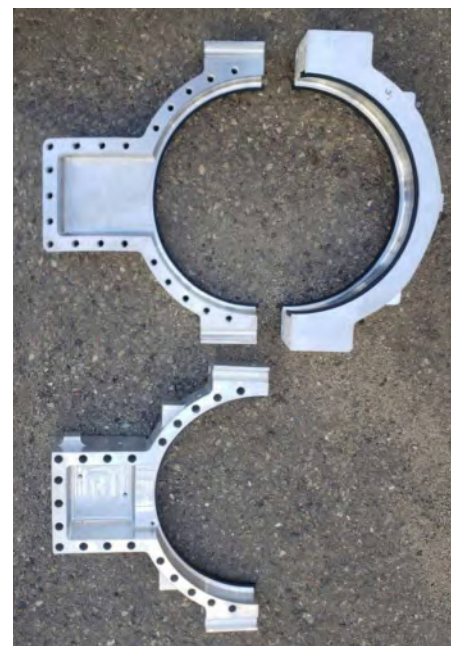


Figure 4. Top left: Open face flange and butterfly valve. This configuration will not support the Drill and Inject technique. Top: A three-part clamp butterfly valve. Bottom: A three-part clamp butterfly valve installed.



Figure 3. Drill and Inject technique: Online leak seal

In addition to open-faced flanges, this technique has been used on flanges on pumps, fault pressure relays, access hatches, bushing flanges and bushing turrets (Figure 5).

Again, no draining of oil, disassembly of components or outage are needed, unless it is required for safe work clearance for the technicians performing the work. Outages, if needed, will only be for the duration of the work, and for some cure time. Typically, the apparatus is returned to service the next day after the repair is performed.

If the leaking component is in close proximity to the energized conductors and the application of an aluminum clamp may compromise electrical clearances, an external clamp can be precision fabricated of PVC material

with an internal cavity filled with the leak seal material. This repair has been commonly performed on CT lead through bushings into transformer main tanks as well as around low voltage bushings [480 V and below] on distribution transformers with limited clearance between the phases.

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Other Unique Repairs

In addition to the common piping flange leaks and those that have been mentioned above, there are other unique repairs that can be performed with this leak seal technique:

- Radiator fin leaks — application of an external clamp
- NLTC operating rod penetration; failure of the packing/bushing around this rod — external clamp
- Large open-faced flanges between sections of transformer tanks, such as the flange between the main tank and an LTC compartment
- Interface in bushings between porcelain and steel flange — often there is a gasket in a bushing between the porcelain insulating column and the bushing base. This gasket can fail and leak oil. The solution is to fabricate

a clamp filled with sealant to enclose on this interface surface.

This technique is also the most common solution for addressing leaks in SF6 filled CB bushings.

Properties of the Leak Seal Compound

For all leak seal repairs performed on electrical substation apparatus, only one type of leak seal compound is used, regardless if the device is a transformer, oil circuit breaker (OCB) or gas circuit breaker (GCB). The leak seal material will not adversely react with transformer oil, nitrogen gas used in a transformer blanket, nor OCB oil or SF6 gas. When fully cured, the leak seal compound is always soft and flexible, and it feels and behaves the same as OEM

nitrile rubber gasket material. The cured compound material does not adhere to the internal surfaces of a gasket groove, nor to the internal cavity of an external clamp. Thus, if the leak seal repaired flange requires disassembly for other repairs of the apparatus, the cured leak seal compound can be easily peeled away with a simple tool, even a pocket knife (Figure 6).

If it is necessary, sometime after the repair is completed, to disassemble the component, upon reassembly of the flange either a new OEM gasket can be put in place of the removed leak seal compound, or, in the case of a repair with an external clamp, the leak seal technicians can be called back to reinject the clamp with new leak seal compound, restoring the leak to its repaired state.



Figure 5. Top left: Clamp installed on transformer oil pump. Top right: Clamp installed around a top-mounted sudden pressure relay leaking oil at its mounting flange. Bottom left: Clamp being installed on the flange of a transformer access hatch. Bottom right: Transformer bushing turret clamp.

A skilled high-pressure leak seal technician is not necessarily best skilled for the low-pressure technique and is potentially not going to do the best repair.

Thus, a firm that specializes in the low-pressure electric equipment repair technique is most likely to perform a successful leak seal repair.

Oil Circuit Breakers

Oil Circuit Breakers (OCBs) have flanges, bushings and valves that are very similar to those found on large power transformers, thus, the same repair techniques can be applied to them. The most common repair is to address failed gaskets in HV OCB bushings at the interface between the porcelain and steel flange at the base of these bushings.

This leak is so common that the leak seal firms have made aluminum castings of this specific clamp that is fine-tuned by machining to tailor it to the specific bushing. This cast clamp is more economical to fabricate in multiple quantities than machining a unique clamp from a block of aluminum for each application.

SF6 Gas Circuit Breakers

Gas Circuit Breakers (GCBs) have multiple flanges on bushings and other components that are ideal candidates for leak seal repairs via the external clamp repair technique (Figure 7).



Figure 6. Left: Portion of clamp removed showing cured sealant. Top: Same repair, sealant cut away showing its flexibility.

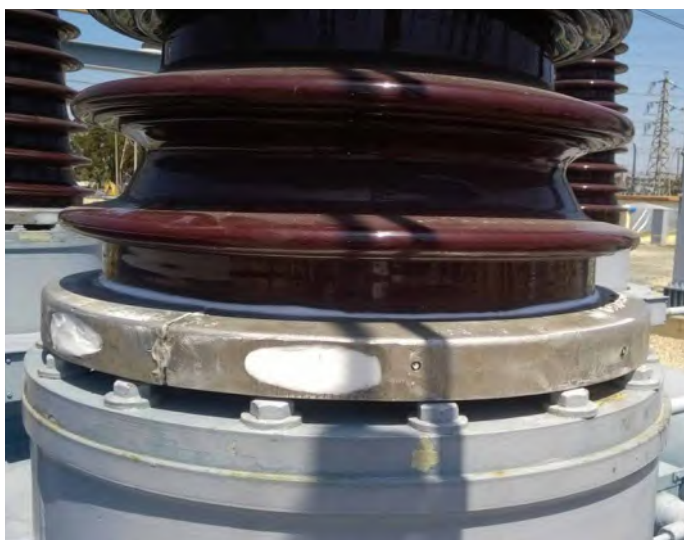


Figure 7. Left: Clamp on an EHV GCB bushing base. Right: Clamp enclosing on the end bell flange of an EHV GCB interrupter tank.



Additionally, leaks in instrument/metering tubing, where threaded fittings are used, can be repaired with external clamps. As in the case with transformers, to perform complete regasket overhauls on large EHV GCBs, an extended outage with degassing of the GCB and opening up all components is required, as well as the testing and adjusting of the GCB mechanism upon completion of the leak repairs, all of which is time and labor intensive, and costly.

With these leak seal techniques, no disassembly or full gas removal is necessary. Outages are necessary only for the duration of the work and post repair leak testing the next day to assure all leaks have been corrected.

Today, there are only a few leak-sealing contractors still performing the low-pressure repair technique in the North American continent, and only one firm that specializes in only low-pressure leak-sealing technique exclusively on electric substation equipment.

History of Online Leak Seal Repairs

This repair technique is something that was derived from the traditional high pressure leak sealing that has been performed for many years on high pressure piping in power

generation plants, refineries, and other chemical processing plants. In 1988 one of the established high pressure leak-sealing specialists was approached by a U.S. electric utility's senior equipment specialist in their Substation Services Group and asked if it was possible to apply the high-pressure leak seal techniques to repairing transformer oil leaks. The utility equipment engineer worked with the leak seal specialist to develop the low-pressure leak seal technique and the Substation Leak Seal Services, as we know it today, was born. This low-pressure technique was further developed and performed by several leak-sealing contractors around the country. Today, there are only a few leak-sealing contractors still performing this repair technique in the North American continent, and only one firm that specializes in only low-pressure leak-sealing technique exclusively on electric substation equipment. A skilled high-pressure leak seal technician is not necessarily best skilled for this low-pressure technique and is potentially not going to do the best repair. Thus, a firm that specializes in the low-pressure electric equipment repair technique is most likely to perform a successful leak seal repair.

The ability to address maintenance issues such as oil and SF6 leaks in a quick and short outage manner will always be a major benefit, so the online leak sealing repair technique will most likely be a popular option.

Future of Online Leak Sealing

Large power transformers and EHV circuit breakers are going to continue to be the heart of the electric utility grid. As sources of generation evolve perhaps away from large central power plants to more widely distributed wind and solar farms, the need for a reliable transmission grid will be as important as ever. Plus, the ability to get extended outages for major overhaul of the apparatus will be ever challenged. The ability to address maintenance issues such as oil and SF6 leaks in a quick and short outage manner will be of major benefit. This author predicts that this repair technique will be a popular option. In addition, the leak-sealing specialists are embracing new technologies such as modeling clamp design on 3D printers to test-fit a new clamp prior to fabrication in aluminum to assure proper fit. Also, these technicians are exploring the use of portable scanning devices to measure leaking flanges and fittings from a safe distance for clamps, without getting an electrical outage for the measurement phase of the repair. These new technologies will be beneficial in adding to the success of this leak repair technique.

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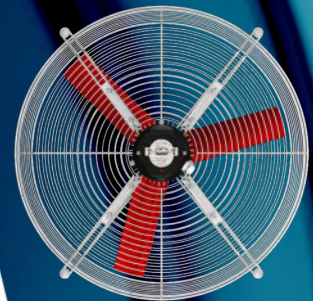
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**NETWORK
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TMC Transformers is a wide-reaching company, with a long experience in the design and manufacture of **medium and low voltage dry type transformers and reactors**, both using cast resin and VPI technology.

All the products are ideal for distribution and special applications: two different technologies combined under a single roof, to offer to customers the most suitable technology and service.

TMC is manufacturing dry type transformers and reactors for all applications worldwide, such as industry, building and infrastructures, traction substations, marine and offshore, oil and gas, renewable energy, battery storage, mining and data centers.

TMC has a large customer base, which led to the development of all types of **customized solutions** in the world of dry transformers. This experience has made possible the development of creative projects adapted to the needs of the clients, both in transformers for **indoor and outdoor installation**, that are able to reach temperatures of -50°C in operation, as well as incorporating different cooling systems (natural air, forced with exchangers, air-water or air-air).

TMC invests heavily in research and development. Dry transformers continue to evolve: new materials, resins, types of insulation, cooling systems. In fact, a team of technical experts, electrical and mechanical engineers make new developments and solutions possible for our customers. Tools and methodologies such as finite elements ensure the highest quality product, capable of withstanding short-circuit mechanical stresses and maintaining operational reliability.

The IEEE T&D Exhibition in New Orleans – April 25-28, 2022 – represents an opportunity for energy professionals to reconnect and explore a range of ideas driving change in the industry and TMC will promote solutions and equipment in the electrical transmission and distribution industry.

TMC focuses its participation in this fair on **Dry Type Submersible Network Transformers** suitable for application in underground vaults on sidewalks in densely populated cities.

In case of heavy rain, these vaults can be flooded and for this reason the transformer is located inside a completely **sealed tank**. Dry type submersible network transformers do not contain oil, avoiding risks of fire propagation in the cities; they are made of entirely welded tank and supplied with external tap changer that facilitates the voltage regulation according to the network. The footprint is similar to liquid-filled units so they are easily interchangeable.

Network transformers are the ideal solution for supplying and distributing energy within infrastructure projects aiming at **high efficiency** and **fire safety**. The insulation system is flame retardant and self-extinguishing, making them a safe and reliable choice over combustible fluid-filled transformers.

At the Exhibition, TMC plans to promote the network transformer developed by the **company's R&D team**, interact with customers, share experiences and advise customers on TMC's full range of solutions and proposals in dry transformers.



Grid Innovations and Digital Transformation

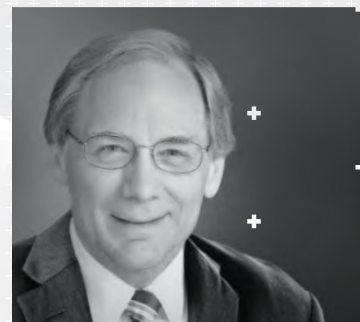
by **Mital Kanabar**
John McDonald
and **Palak Parikh**



Grid innovations and digital transformation of power substations are accelerating the energy transition for global utilities.



Dr. Mital Kanabar is an Office of Innovation leader and global Applications Architect in Grid Automation (GA) of Grid Solutions business, GE Renewable Energy at GE Grid IQ Center in Ontario, Canada. Mital has 15+ years of power industry experience and holds 12+ international patent applications. He has published more than 50 journal/conference papers, 5 industrial magazine articles, and a book chapter. He holds an honorary Adjunct Professor position at OntarioTech University, Canada. Mital is also serving as a Chair and Vice-Chair of three Working Groups (WGs) at IEEE PES Power System Relaying Committee (PSRC). And, he is an active member of several technical working groups at IEEE, IEC, NERC and NASPI. Mital earned his PhD degree from the University of Western Ontario, London, Canada.



John McDonald, P.E. is Smart Grid Business Development Leader for GE's Grid Solutions business. John has 47 years of experience in the electric utility T&D industry. John received his B.S.E.E. and M.S.E.E. (Power Engineering) degrees from Purdue University, and an M.B.A. (Finance) degree from the University of California-Berkeley. John is a Life Fellow of IEEE (member for 50 years), and has received a number of distinguished IEEE and IEEE PES medals and awards. John is Past President of the IEEE PES, the VP for Technical Activities for the US National Committee (USNC) of CIGRE, the Past Chair of the IEEE PES Substations Committee, the IEEE Division VII Past Director, and a member of the US National Academy of Engineering.

The energy transition is at hand, but its success relies on our ability to adapt our aging power infrastructure to support the integration of more renewable energy resources.



Palak Parikh, PhD PEng is a Lead Application Engineer with GE's Grid Automations' Product R&D group, focusing on various product designs in the area of Distribution Automation & Protection. She received her Master's and Bachelor's degree in electrical engineering from Sardar Patel University, India. She pursued her PhD from the University of Western Ontario, Canada. Palak has expertise in the area of distribution automation, microgrid solutions, and power system protection. She has authored more than 30 international journal and conference articles and holds 1 patent.

Key Challenges and Opportunities with Grid Modernization

The energy transition is at hand, but its success relies on our ability to adapt our aging power infrastructure to support the integration of more renewable energy resources. Innovation and the digital transformation of the grid substation are crucial to evolving our technology rapidly enough to meet the world's rising demands of green energy. In this article, we discuss four grid technological innovations that are changing the way power substations work and giving grid operators the ability to better manage those substations and the network as a whole—paving the way to meet changing energy demands.

First, we examine the use of data in the move from time-based to condition-based maintenance and performance of primary substation equipment, such as power transformers. We also explore grid sensing with analytics to improve network utilization. We then consider the new flexible architectures of the digital substation, and how they create a more scalable, grid-reliable control and automation platform that is ideal for tomorrow's power

system evolutions. Next, we look at grid system integrity and protection schemes for high-speed grid stability controls. Finally, we discover how secured wireless technologies, such as licensed/unlicensed radios or private LTE (long-term evolution) networks, are bringing industrial-grade reliability and security with the integration of distributed energy resources (DERs).

Grid Infrastructure - Major Challenges and Opportunities

The electrical grid has been largely evolving for over 100+ years. So, why now? In speaking with many global utilities and heavy power users, three clear factors have emerged as being driving forces: the need and push for decarbonization, the decentralization caused by the growth of renewables and DERs, and digitization—our ability to connect more assets and visualize more data than ever before. Digital transformation enabled by grid modernization technology in the transmission and distribution system will play a central role in the energy transition.

Power grid infrastructure has been built and maintained over the past century to deliver reliable, safer, and affordable electricity across communities and

industries. With the integration of large renewable energy farms on the transmission grid, and distributed energy resources on distribution networks, several challenges and opportunities have presented themselves during the modernizing of decades-old grid infrastructures.

Digital transformation with grid modernization technology for the transmission and distribution system will play the central role between renewable generation and prosumers of energy. The four key aspects shown in Figure 1 illustrate grid modernization through innovation and digital transformation, including:

- Improving grid performance and utilization of the existing infrastructure with innovations in grid asset (e.g., transformers, feeders) monitoring;
- Enhancing grid reliability and flexibility with digital substations and software-defined automation and controls;
- Maintaining grid stability and resiliency on large integrations of inverter-based renewable energy resources using system integrity protection schemes; and
- Enabling cyber security with end-to-end communication for geographically dispersed DERs.

Figure 1. Grid challenges and opportunities

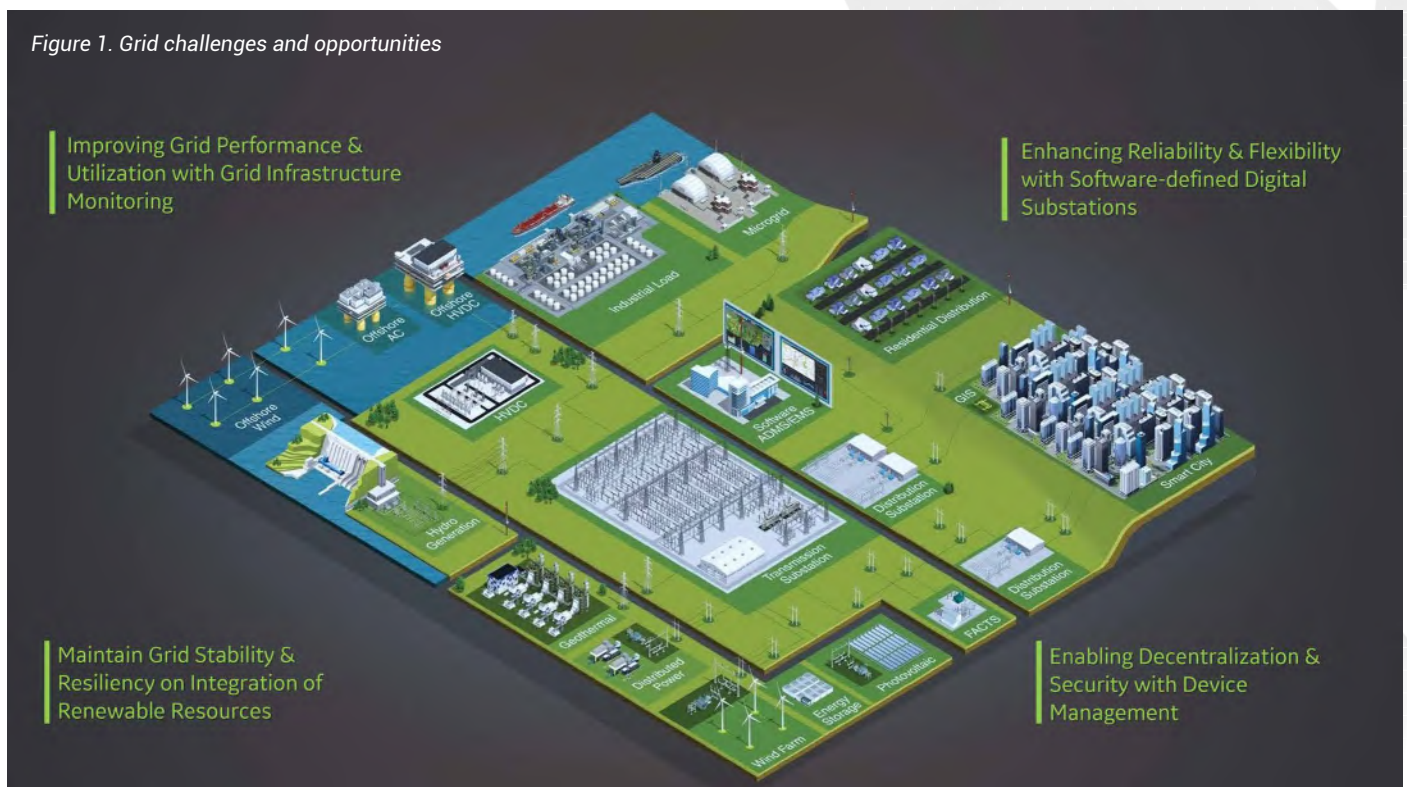
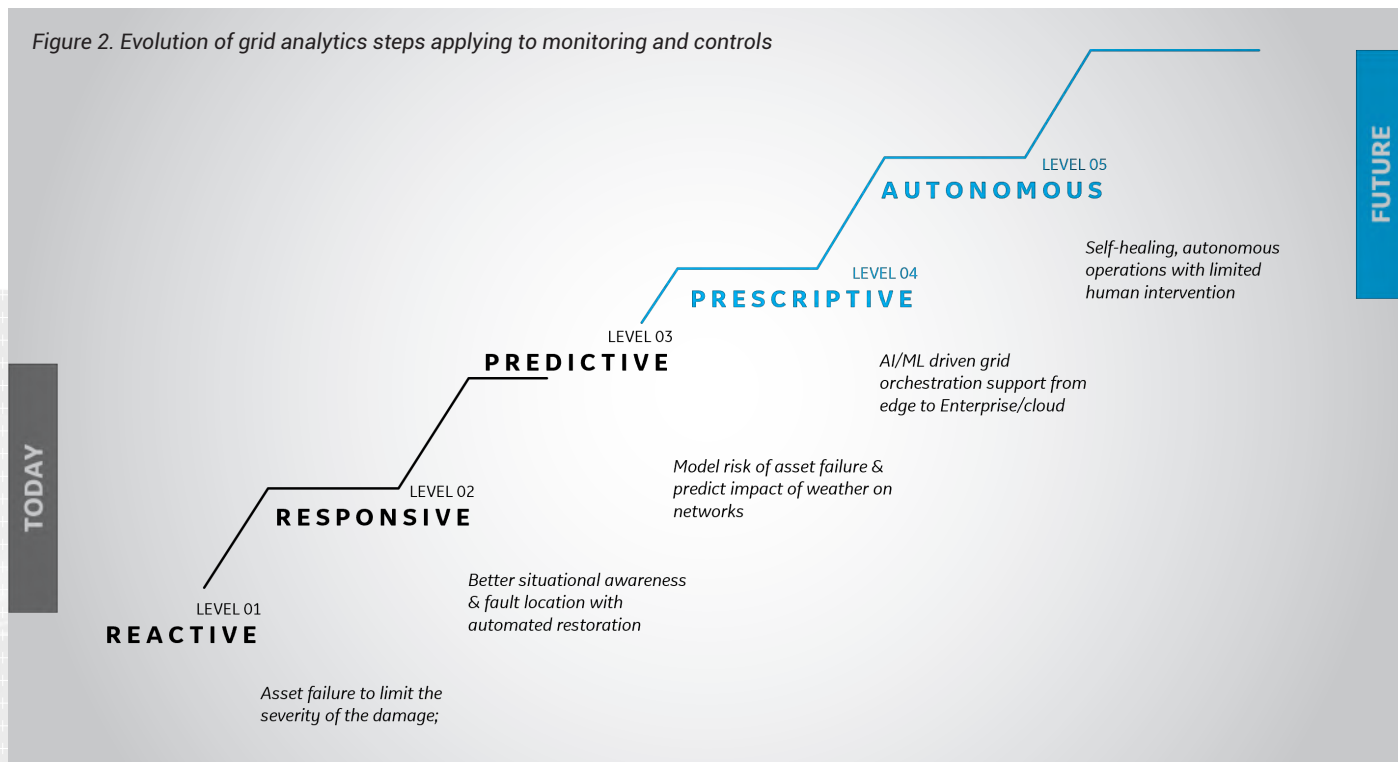


Figure 2. Evolution of grid analytics steps applying to monitoring and controls



Evolving Grid Analytics Innovations

Power grid networks and equipment infrastructure are monitored and controlled by edge devices with sensors and actuators with some level of intelligent analytics. As illustrated in Figure 2, the evolution of grid edge analytics innovations moves from a reactive management strategy that responds to failures after they occur to a more autonomous future state with self-healing.

The majority of existing grid edge analytics are reactive to failures to limit damage, with limited responsiveness to restore automatically. The predictive stage may utilize system or asset

models with a combination of physics and machine learning methods, including anomaly detection, classifications, and/or learned patterns. Further grid innovations can be applied to suggest potential implications and recommended actions. Finally, the autonomous grid with self-healing would use edge-to-edge communications with very limited or no human interventions.

Grid Innovations for Online Asset Condition Monitoring

The aging of the existing installed base and the lack of sufficient upgrades of the grid infrastructure are challenging for grid reliability, resiliency, and affordability.

There are several methods of condition monitoring, generally categorized as the following:

- **Automatic and online:** Continuous monitoring applied while the asset is running; analysis performed without human intervention
- **Automatic and offline:** Scheduled monitoring applied when the asset is stopped; analysis performed without human intervention.
- **Manual and online:** Continuous monitoring applied while the asset is running; analysis performed manually on collected data.
- **Manual and offline:** Scheduled monitoring applied when the asset is stopped; analysis performed manually on collected data.

Table 1. Grid asset management challenges and solution strategies

CHALLENGES	SOLUTION STRATEGIES
Aging grid infrastructure - assets reaching the end of life in an environment of increased capital expenditure (CAPEX) constraints	Extension of life for aging assets and prioritization based on asset risk index/score. Defer cost of replacement using continuous asset monitoring and diagnosis.
Operational expenditure (OPEX) constraints leave overwhelmed resources and difficult preventive maintenance programs	Optimize maintenance schedules and shift from schedule-based to condition-based or preventive maintenance
Accidental and hazardous incidences, risk of personnel safety at workplace, human errors	Mitigation techniques to prevent hazardous incidences, establish safety processes, and train workforce
Unplanned outages and unexpected failures of system devices	Prevent unexpected failures and save the cost of unplanned outage or production loss with real-time integrated condition monitoring and controls
Expertise reducing due to retiring workforce	Digitalization of analysis and automation tools that can provide actionable intelligence

Normally, the online methods require additional devices connected to the sensors applied to the equipment whereas the offline methods require scheduled shutdown to perform the tests. Autonomous monitoring and diagnostics need enough processing capabilities and memory within an edge device whereas manual monitoring and diagnostics require time from an expert team to perform analysis and prepare asset health reports.

Power Transformer Example

An example of power transformer equipment monitoring and diagnostics is presented below which can provide risk index and score with actionable condition-based maintenance through a combination of electrical, chemical, and thermal data. Power transformers are among the most critical power substation assets required to maintain a reliable and efficient power supply. Yet more than half the transformers in the developed world are several decades old or older. With almost half of transformer failures caused by insulation degradation and electrical abnormalities due to aging, extending the life of these devices has become a top priority for major power utilities.

Figure 3 presents integrated condition monitoring of the transformer using protection relay and dissolved gas analyzer data. Traditionally, a transformer protection relay is connected to current and voltage transformers to obtain the currents and voltages needed to detect electrical faults. It is interfaced with circuit breakers for control actions. In addition, dissolved gas analyzer devices connected to a transformer can draw oil samples regularly and perform continuous chemical analysis.

In the past, these two distinct systems (electrical protection and chemical monitoring) have not been interconnected. Since both systems provide much-needed asset and performance management data, bringing them together provides a more comprehensive view of the transformer's overall health as shown in the figure. This integrated approach of combining two systems (a protection relay with electrical functions and a dissolved gas analyzer with chemical analysis) allows tracking of trending incipient fault events with the same timestamps, a correlation between the electrical and chemical models, and integrated asset health analysis and reporting.

With deep equipment design expertise, proactive functions are designed to continuously perform online equipment condition monitoring in combination with protection and control measurements of the equipment to be protected. Proactive functions take a holistic approach to the equipment to be protected, capturing the entire evolution of a potential failure, including:

- detecting an anomaly or degradation of a subcomponent of the asset,
- alarming the condition, and
- recording and logging the signals and evolving changes.

Proactive functions are essential to detect critical asset degradation or anomaly conditions before they evolve into catastrophic failures. This avoidance of costs, damage, and reliability costs justifies the investment in this digital transformation.

Data correlation models are time-aligned and trended among electrical, chemical, and thermal characteristics through a range of transformer conditions. Reports from the system (including the energization record, integrated transformer fault report, and transformer health report)

Figure 3. Holistic electrical, chemical and thermal models for transformer monitoring and diagnostics

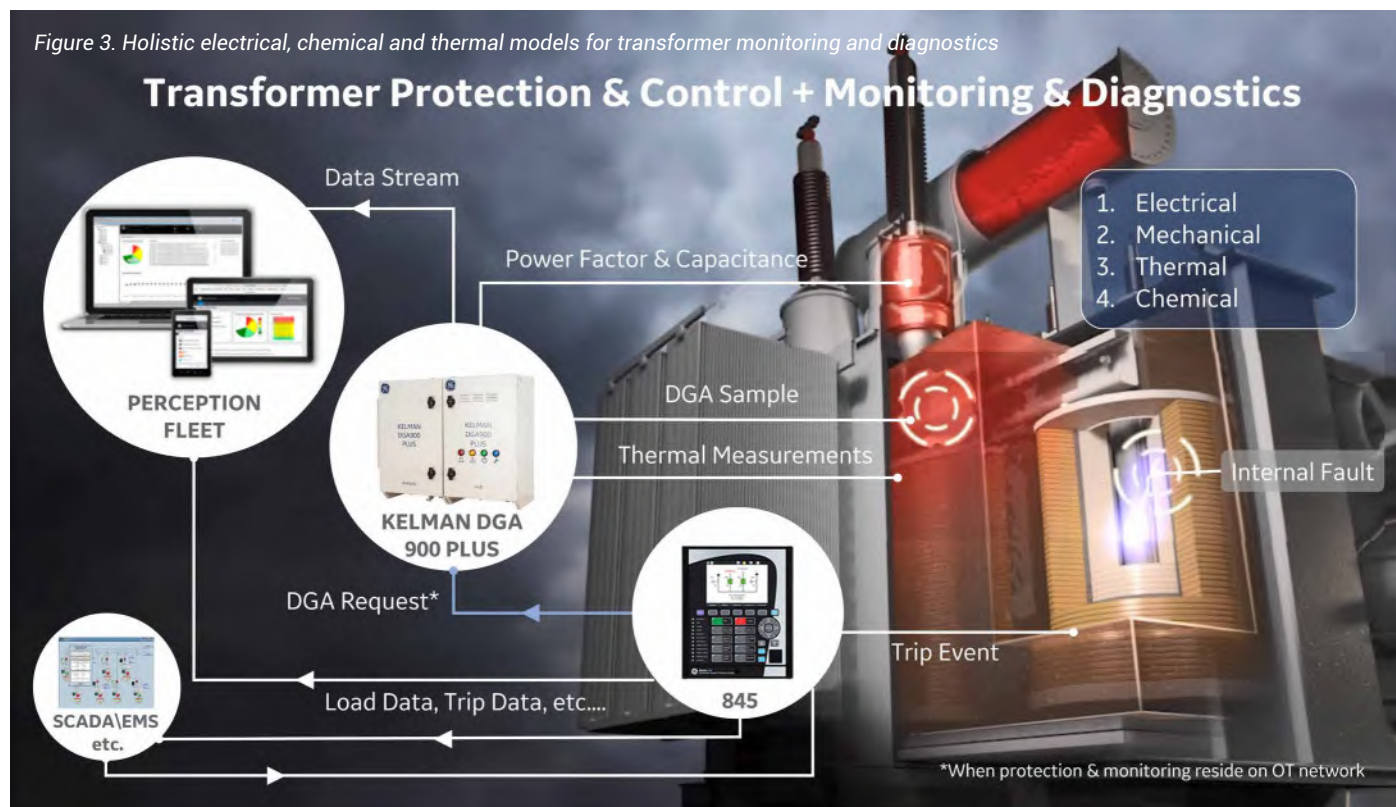
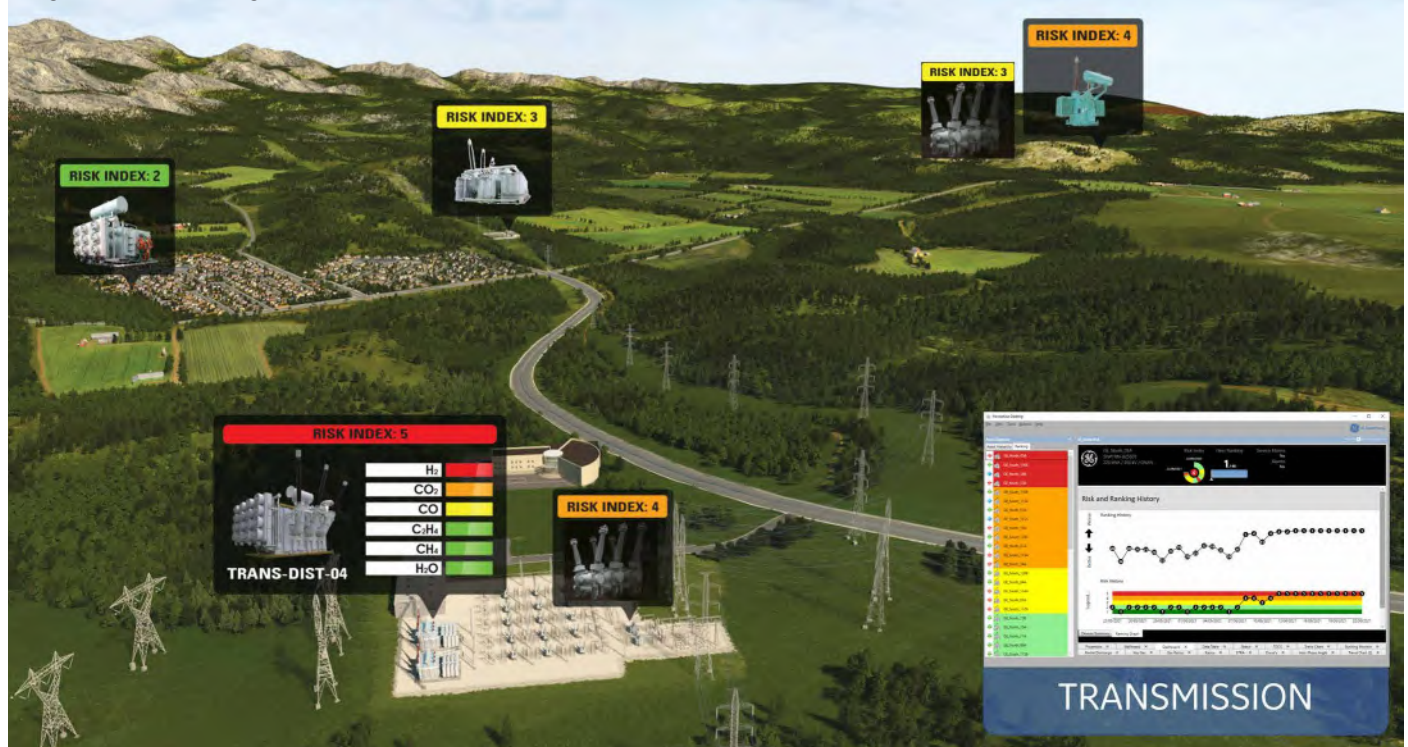


Figure 4. Fleet-view of grid asset risk indices



allow capturing key operational dynamics that provide insight about both internal and through-fault conditions. Critical transformer data is compiled into reports and models that are easy to interpret, supporting informed decision-making. This ultimately delivers conditions for asset management optimization and potential for a transformer life extension, enabling operators to reduce capital and operational

expenditures while maintaining the power system reliability demanded by today's market.

With advancements in data analytics, interoperable data communication, and high-speed networking, the availability of data for advanced analytics is ushering in a new era of predictive analytics. New predictive analytics can be applied to build proactive functions which do not just

limit but can prevent catastrophic events. Digital protection relays are checking for anomalies around every 2ms. Instead of witnessing the evolution of equipment failure until the set threshold of traditional protection function is reached, proactive functions can provide early warning upon detection of abnormal operating conditions. These can be key inputs to managing assets using digital data.

Figure 5. An example of holistic transformer health models



Figure 5 presents an example of a transformer model from its health report. When a protective relay detects an internal fault, it trips the transformer. External or through faults, however, can result in high current flow through the transformer before the device is tripped offline, causing significant stress on the transformer. A typical distribution utility experiences about 15 to 20 through faults each year even in advanced distribution systems. Research demonstrates that many transformers that fail catastrophically start showing indications of problems immediately following a through fault event. Developing situations such as these are more easily detected with visibility into pre- and post-fault electrical, chemical, and thermal data. In the transformer relay, this data is delivered via the user-friendly integrated transformer fault report. This graphical fault report can provide a clear visual indication of the fault condition as well as any changes to the transformer's health.

This integrated solution provides a heightened level of visibility, allowing the data to be applied in a meaningful way to maintenance or troubleshooting needs. An asset health report gives a snapshot of the transformer's condition, and helps utilities analyze the following:

- Risk assessment of the transformer population in service, especially critical transformers and important connections;
- Condition assessment of individual transformers, identifying those which may require follow-up such as visual inspection, diagnostic measurements, and maintenance; and
- Proactive risk mitigation actions for transformer asset management.

An Example of Grid Utilization and Fault Location

The integration of renewable generation into existing grids is increasing. One of the main challenges is that power flows are uneven and decentralized, and line loading at specific points in the network becomes uncertain with the change in the feed. This challenge is reduced with real-time or near-time grid visibility. Using dynamic line rating data monitored by sensors, the power handling capacity of the line at specific points can be determined. This allows the utility to provide improved power quality and a better-managed system with increased visibility into the network. With a regulatory requirement to minimize outage times, it is important to detect and locate faults and disturbances across the distribution grid using

overhead line monitoring devices. The integration of monitoring data received from line monitoring devices with distribution management system helps improve the reliability and safety of the system, and thus optimizes the use of the network. Typically, line monitoring devices are mounted at strategic points in the overhead network. The system is shown in Figure 6.

These line sensors measure current and calculate both amplitude and phase of the root-mean-square value, and have built-in communications. The sensors can pick up fault currents and report this current data back via radio to the sensor network gateway (SNG). The SNG links a network of sensors together, sending commands to the sensors and receiving data. This data consists of current values, fault event current data, or other related information, such as temperature, etc. The SNG links back to the data acquisition communicator unit. The unit is generally mounted in the substation, and its function is to record the activity of the sensor network. It acts as a database for line status including events like line loading, tripping faults, or sub-tripping events. The data acquisition communicator also links the sensor network to the system software controls.

Figure 6. Line monitoring interface system

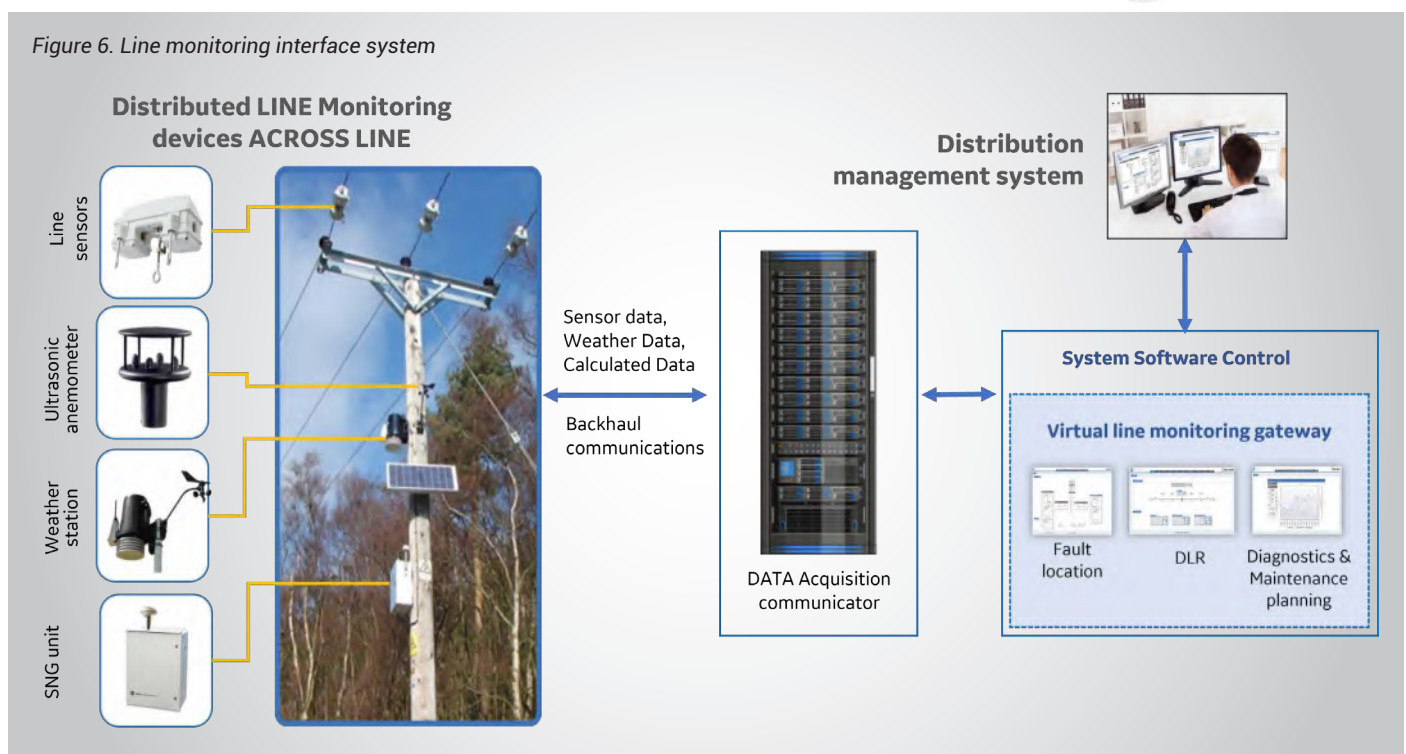
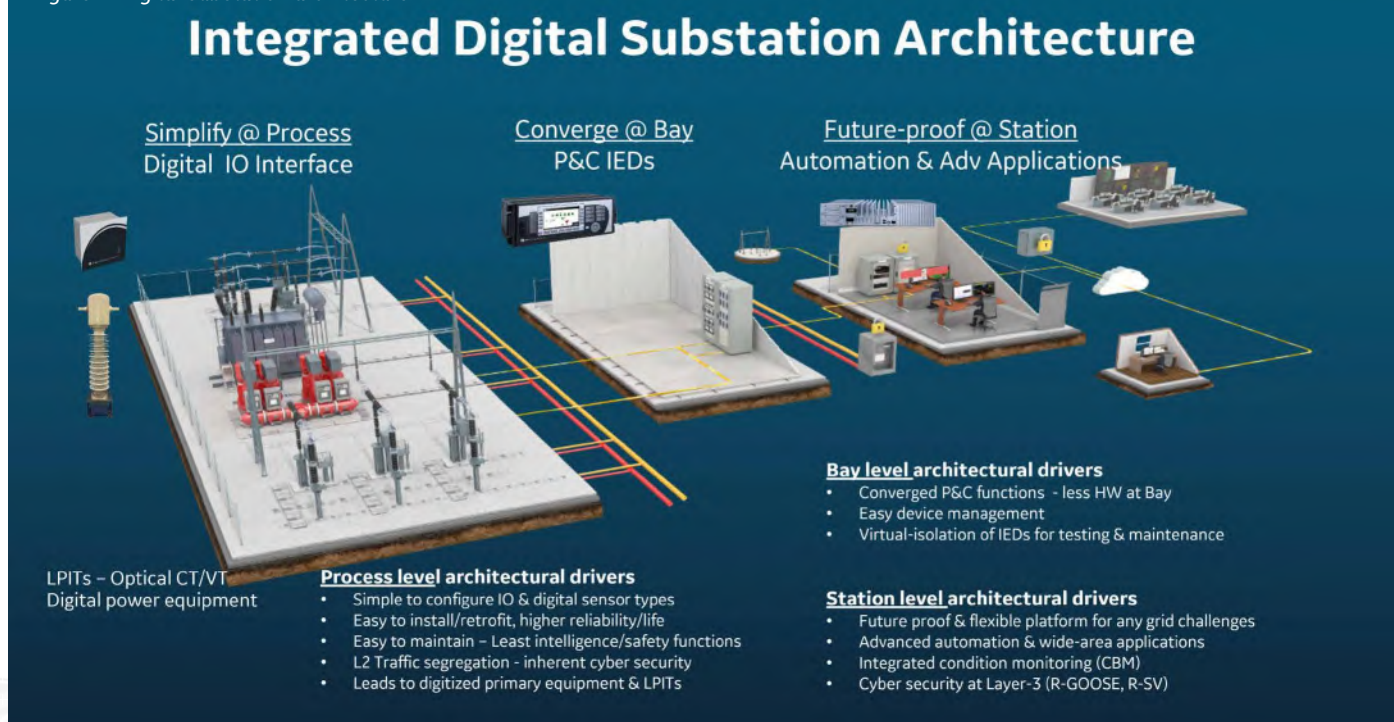


Figure 7. Digital substation architecture



The system software controls the entire network at one central location and can include a virtual line sensing gateway that provides access to faults and line loading data centrally. It also provides a platform for line monitoring analytical applications such as:

- fault location and fault signature,
- dynamic line rating,
- local sag/clearance estimation, and
- remote system diagnostics and maintenance applications including remote SNG and line sensor firmware updates.

This software can be stand-alone or be integrated into a distribution management system with mapping and maintenance functionality.

Line sensors can be installed at demarcation points where the utility network connects to local grids, allowing the utility to discover line faults and determine whether the issues are upstream or downstream. This saves them about 35% in the number of truck rolls. The combination of auto-recloser technology and down conductor detection line monitoring can help mitigate wildfires risks. Also, with the combination of distributed fault detection, isolation, and restoration, this combined technology can help the utility move towards the goal of a “self-healing” grid.

As substation devices continue to evolve, and we continue to capture and visualize more ‘real-time’ data about individual substation assets, the next level of value for grid edge peer-to-peer device analytics may be moving from predictive to autonomous operation. We are starting to see this evolution now as machine learning and artificial intelligence capabilities are being implemented into field and edge devices. For example, protection relays can trend operational data and use built-in artificial intelligence/machine learning algorithms supervised by logic and controls to take prescribed and approved actions—thereby minimizing the need for truck rolls or manual human intervention.

Evolving Digital Transformation Across Grid Infrastructures

This section presents the digital transformation applied within the substation as well as outside the fence of transmission and distribution networks.

Architecting Flexibility and Safety with Digital Substations

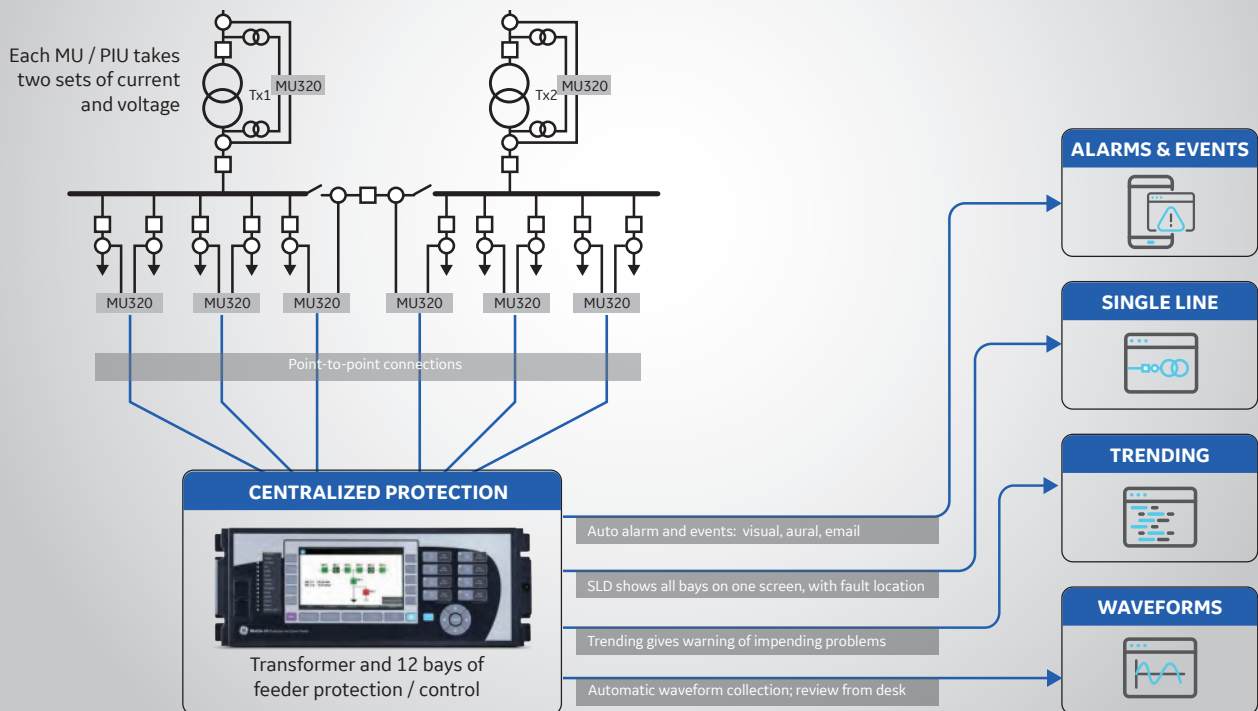
More and more utilities are investing in new protection, automation, control (PAC) systems in substations. They are doing this for several reasons.

First, it allows for a smaller control house footprint which saves money in construction. It also allows for significantly less wiring between devices which lowers cost and reduces the opportunity for miswiring. It also allows for significant data to be available for utilities to use to monitor systems and leverage in their asset management programs. The SF₆-free technology innovations such as green gas (g³) enabled switchgear already provide clean primary equipment for the grid.

Figure 7 shows the hierarchical architecture of a digital substation PAC system divided into three existing levels: process, bay, and station. Considering the technology cycles discussed earlier, the process level needs to “simplify” through digitization using open standard data sharing communication interfaces (i.e., IEC 61850-9-2LE and/or IEC61869-9/13). The bay level should be able to “converge” PAC applications with centralized substation protection systems. The modularized hardware of PAC intelligent electronic devices (IEDs) can provide completely independent communication ports to facilitate cyber security perimeter segregation for process bus and station bus. The station bus can be designed as “future-proof” with software-defined

Figure 8. A centralized protection and control system

ONE CENTRAL RELAY FOR A SWITCHGEAR/SUBSTATION



applications for the grid of the future. As the grid/substation evolves (such as through renewables penetration), the scalable substation control/automation application platform can allow future applications and solutions without replacing the hardware or platform software.

Process interface units installed close to, or as part of, primary equipment, are used to digitize the signal interface and communicate to process bus over interoperable IEC 61850-9-2 or IEC 61869-9/13 standards. The software and settings at the process level need

to be minimal or, if possible, with minimum settings and segregated layer-2 (ethernet) level traffic. Easy-to-install and maintain hardware delivers higher reliability and, with interoperable protocols, this data would be available to any application at the bay or station level.

Centralized Substation Protection System

Centralized protection and control (CPC) is a concept to combine the function of several IEDs into single hardware as illustrated in Figure 8. This allows more efficient use of processing power

and achieves cost-savings by reducing the amount of hardware used. While achieving the cost-saving is important, CPC shall not compromise the stability and neglect the reliability offered by a conventional solution. Therefore, it is important to find a balance of saving without overlooking the criticality of power system operation.

CPC is not just about a single centralized protection device because this device alone will not bring benefit to the user. CPC is a system involving process-level digitization and a substation human-machine interface. Having all functions running in one

Figure 9. Software-defined grid controller architectures

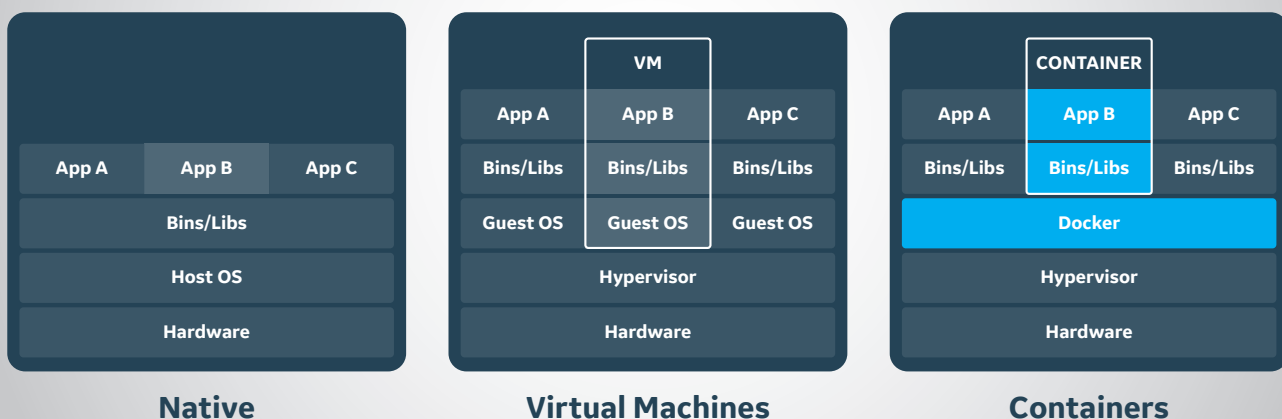
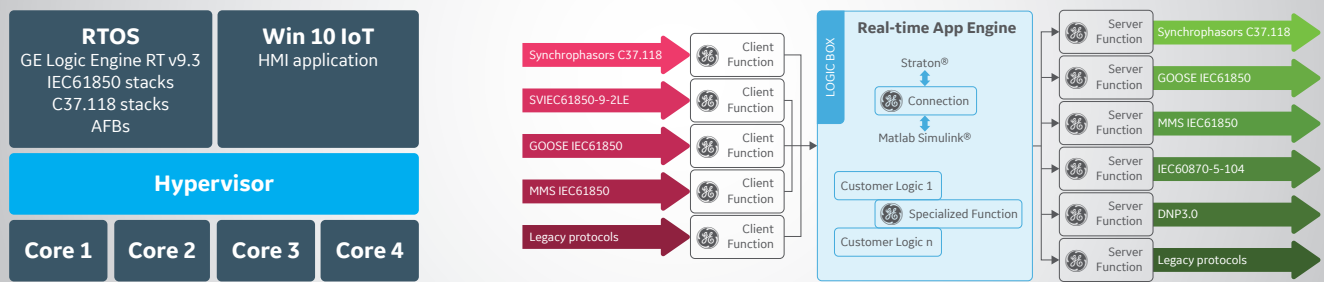


Figure 10. Software-defined advanced automation application system architecture



centralized hardware opens some new requirements, such as the need for robust cyber security in a CPC unit, redundant systems to prevent maloperation due to a faulty device, and time synchronization. Please refer to the IEEE Power and Energy Society Power System Relaying and Control Committee's Working Group K15 report online for more details on the CPC system.

Software-Defined Automation and Controls

Figure 9 presents innovation driving software-defined grid automation and control platforms. The virtualized

architecture may have the potential to migrate non-mission-critical substation automation from native specific hardware platforms to virtual machines or even cloud-native containerized applications.

Figure 10 provides the architecture of an advanced automation application system that allows a real-time operating system with a non-real-time Internet of Things operating system using virtual machine architecture. The hypervisor allows scalable multi-core CPU cores and execution of real-time grid logic along with a non-time-critical human-machine interface type of application.

The advanced software-defined substation automation system shown in Figure 11 is using container-based architecture and a secure edge operating system lighter than typical virtual machines in terms of footprint and memory usage. They boot faster and use fewer resources than virtual machines. They can be deployed seamlessly across development, validation, and production and are easily portable across different computing environments. This system allows enhancement of grid reliability and flexibility to adapt to the changes that come with the integration of more renewable energy resources.

Figure 11. Software-defined grid control architectures

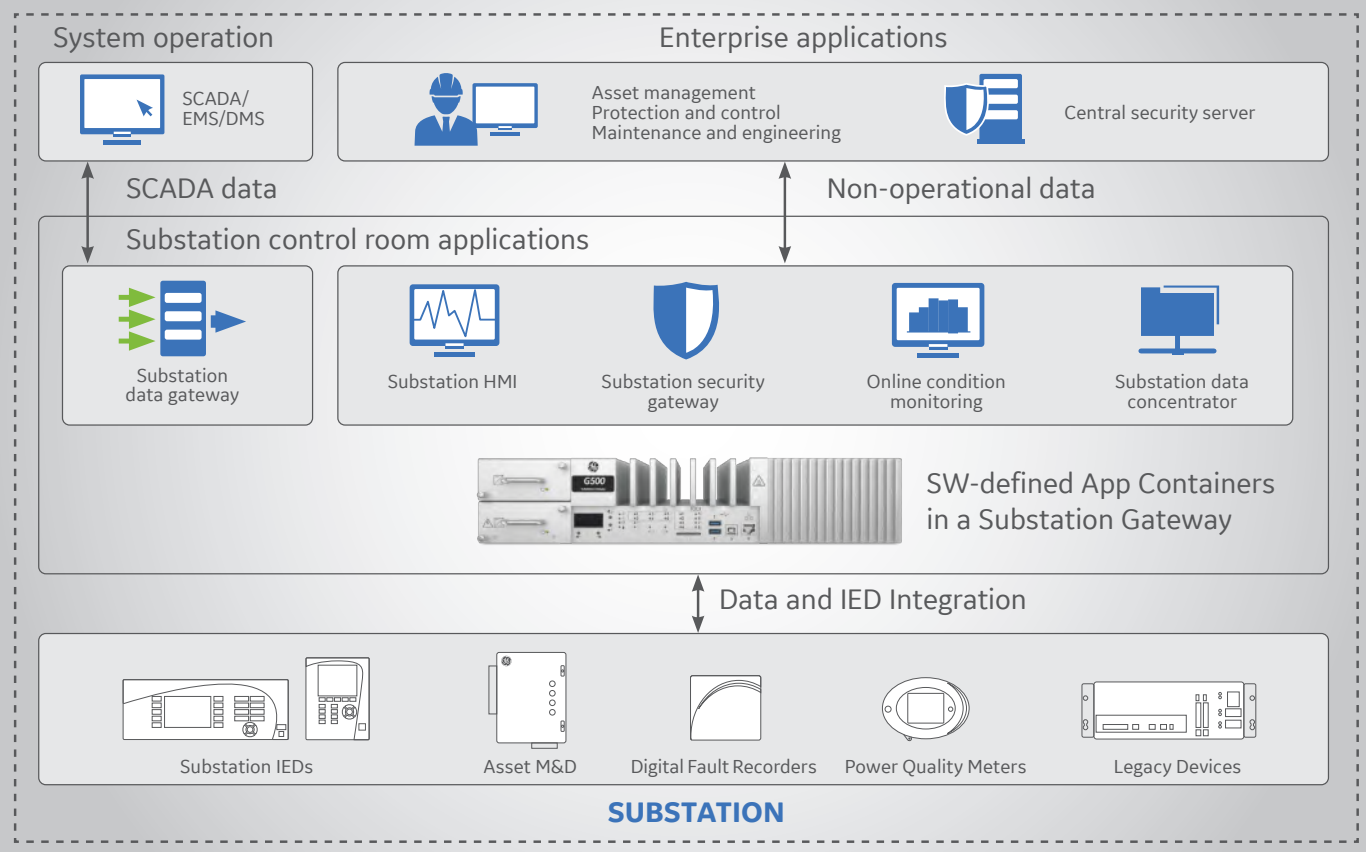
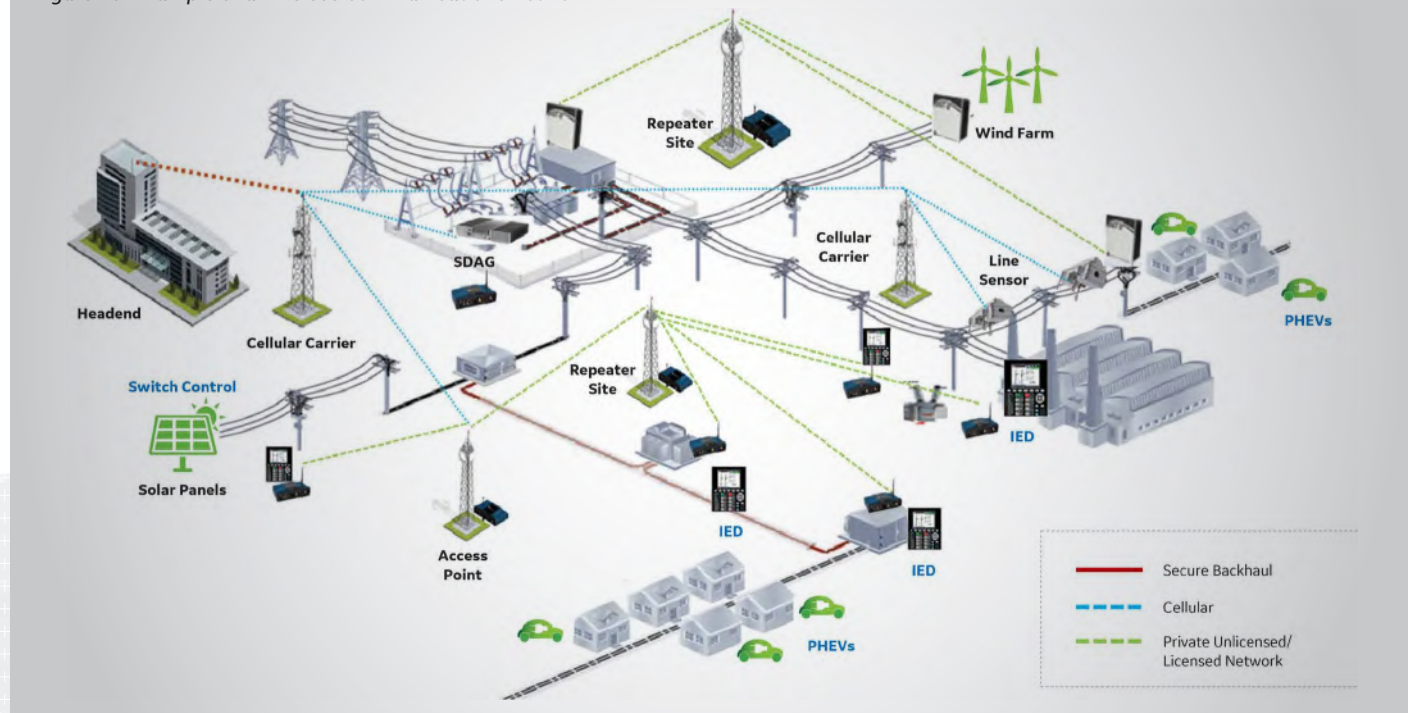


Figure 13. Example of a wireless communications network



IP security (IPSec) and virtual private network (VPN) with key rotation used to enable an end-to-end encrypted IP tunnel through which data can flow securely between utility assets.

Like a private network, a public wireless network allows authorization, authentication, and

accounting services. Suitable wireless technology should be selected based on criteria such as bandwidth, range, data latency, and regional frequency spectrum availability. Industrial wireless has already been applied for DER transfer trip, line/feeder fault location, distribution automation, PAC IED

configuration, and remote DER or substation monitoring. The grid of the future will continue to rely on a strong communications infrastructure, and hybrid approaches that can extend or supplement existing wired systems with wireless solutions will be in the best position to meet current and future grid needs.

Table 2. Distribution level challenges and solution strategies

DISTRIBUTION LEVEL CHALLENGES – EXISTING AND EVOLVING	POTENTIAL SOLUTIONS
Geographically dispersed assets/devices >> difficult to access and maintain	Smart distribution IED platform across the network
Different devices, capabilities, versions, and configurations >> difficult to manage and train	
Dynamic interconnections – Renewables, microgrids; bi-directional power flows, reliability and efficiency	Distributed Intelligence over ICT and standard protocols (e.g., IEC 61850)
Limited bandwidth, multiple communication protocols and mediums >> difficult to interoperate and integrate	
Evolving regulatory requirements and international standards, difficult to deploy and maintain end-to-end security	Cyber security management
New vulnerabilities and cyber-attack methods	
Aging fleets with many assets reaching the end of design life in an environment of increased capital expenditure (CapEx) constraints	Predictive remote asset management integrated within smart IEDs
Operational (OpEx) constraints resulting in overwhelmed resources and difficult preventive maintenance programs	
Unexpected failures leading to safety concerns, prevention of unplanned outages, risk mitigation	



Conclusions

There is no question that grid innovations and modernization are helping to power the energy transition forward. Globally, the power grid industry needs more investment in grid modernization and the energy transition to allow more green electrons to flow while improving grid reliability, safety, sustainability, and affordability. The many parts and pieces of today's grid infrastructures are insufficient to integrate more renewable resources and maintain supply through extreme external conditions, such as heatwaves or storms. The electric transmission and distribution system needs to be built with seamless bidirectional flow of electricity and secured data while considering hierarchical resilience upon network disruptions.

To address these challenges and unlock sustainable development, utilities are embracing grid innovations and digital transformation across transmission and distribution infrastructures. Grid innovation examples of analytics for automatic

and online condition monitoring of grid networks and equipment are presented to improve grid reliability/availability and optimize operation and maintenance costs. The digitization of data is integrating previously siloed data streams to provide new visibility into the overall health of critical power system assets. Digital transformation of substations protection, automation and control systems with purpose-fit architecture allow convergence and flexibility using international standards for data communication.

Grid resilience and stability are presented with system integrity protection systems using high-speed secured peer-to-peer communications across the wide-area transmission network. At the distribution level for DER management and microgrid's controls can be enabled with recent advancements in industrial wireless technology. It is applied to various power applications which may require lower deployment costs across geographic dispersed areas, mobility/portability, remote location coverage,

rapid installation, etc. Cybersecurity requirements are achieved over both licensed/private and unlicensed/public wireless technology options.

The energy transition demands that we continue to modernize the grid to enable the integration of more renewable and distributed energy resources. Innovations such as those described in this article are helping while entering a new era of clean, reliable, and affordable energy all over the world.

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Continuous monitoring of critical assets is an important aspect of transformational digitization in the grid of the future. As considerably more renewable sources of energy are introduced to the grid, the stresses and strains on new and existing critical power delivery assets increase due to the fluctuating loads, unique operating conditions and differing environments. By providing early identification of incipient faults, continuous monitoring creates the opportunity for business efficiencies and justification for interventions before faults peak.

Enhancing your asset management strategy with continuous monitoring will help to:

- Limit supply interruptions and avoid unplanned outages
- Reduce repair times and the associated costs
- Minimize planned maintenance duration and enable workforce efficiencies
- Implement accurate and targeted condition based maintenance and asset replacement
- Extend overall asset life and manage near-end of life operations



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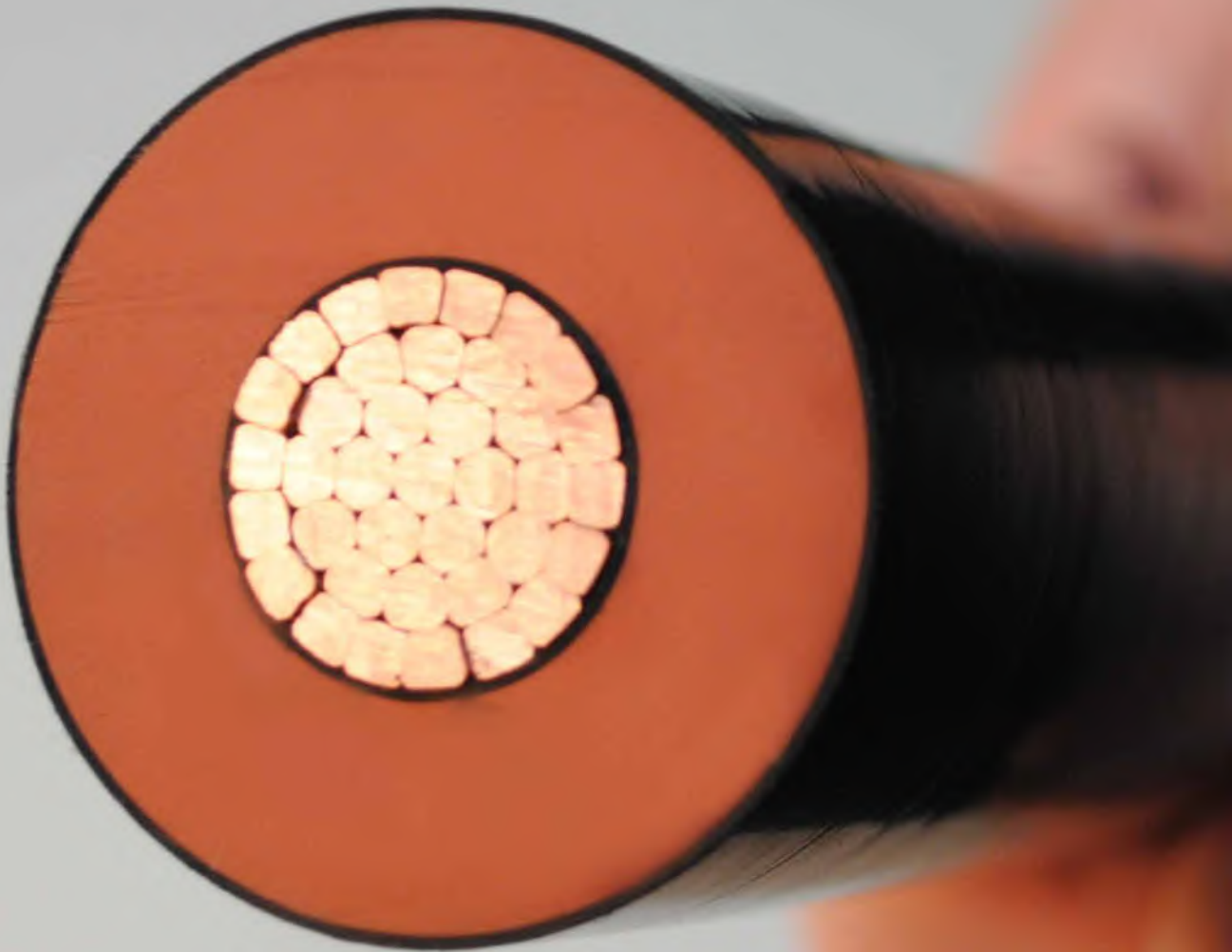
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Power Cable Systems Reliability and Longevity: Past, Present and the Future

by **Ben Lantz**

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Medium and high voltage (5-500 kV) cable systems are one of the most commonly overlooked power system assets and yet they are the arteries enabling reliable grid operation. Their invisibility has led to mystery, a general lack of information sharing, and in some cases, misunderstandings leading to suboptimal operation. In this article we take a step back to promote knowledge sharing and industry best practices by reviewing where we came from, the state of the art, and finally provide a vision for reliability and longevity beyond 100 years of service life.



With over 25 years in the power and energy industry, **Ben Lantz** is currently responsible for IMCORP's technical education and outreach efforts and is the Chairman of the Board for the Power Delivery Intelligence Initiative (PDI2.org), a nonprofit organization dedicated to disseminating T&D best practices. He is a Senior Member of IEEE PES and ICC, and an active or voting member of IEEE DEIS and IAS, American Clean Power, CIGRE, NETA, and a founding member of Electric Power Reliability Alliance. He has served as Chair of IEEE technical committees associated with power system reliability, protection, and testing. He has published dozens of peer reviewed papers and technical conference contributions on the subjects of power system reliability, asset management and diagnostics and is frequently a guest speaker at numerous conferences and seminars.

The Past

Early power cable systems were made of oil impregnated paper insulation incased in a metal moisture barrier. The first cables date back to the early 1900s. Paper insulated lead covered (PILC) cable was a highly successful technology that enabled cable systems to reliably operate at medium and high voltage stress levels for more than 60 years. These cable systems had the benefit of a liquid dielectric (oil) that can move to void areas and provide a “self-healing” mechanism and paper tape layers that allowed technicians to create terminations and splices onsite.

Unfortunately, much of the knowledge and skill to install and maintain paper insulated systems has been lost to retirement and with environmental concerns with oil and lead, they are rapidly being replaced with modern plastic and rubber insulation systems. Operation and maintenance of paper insulated systems was largely based on material limitations and failure mechanisms. Many of the old systems had a maximum operating temperature in the range of 70°C and extreme temperatures could damage the paper irreparably. The most common failure mechanism was associated with conduction through either moisture ingress and ionic conduction or carbonized papers due to a localized lack of oil and partial discharge (PD, described in more detail below). Not surprisingly, the factory and field tests typically recommended were largely based on measurement techniques sensitive to conduction and insulation losses such as DC high potential (HIPOT) with leakage current or AC or very low frequency (VLF, 0.1 Hz) tangent delta (tan delta (TD)).

Medium and high voltage cable systems are one of the most commonly overlooked power system assets and yet they are the arteries enabling reliable grid operation. Their invisibility has led to mystery, a general lack of information sharing, and in some cases, misunderstandings leading to suboptimal operation.

PILC cable cross section

In the 1960s and 70s medium and high voltage solid dielectric (SD) insulation systems were developed including materials such as polyethylene (PE), ethylene propylene rubber (EPR), ethylene propylene diene monomer rubber (EPDM), and silicone rubber. These cable systems were expected to be cheaper and easier to install with less skilled labor; resistant to moisture, and have a 40-year life. The history of what actually happened with these early vintage SD cable systems is one of the major reasons underground is still a mystery to many, and the thought of mass adoption can generate fear of the unknown.

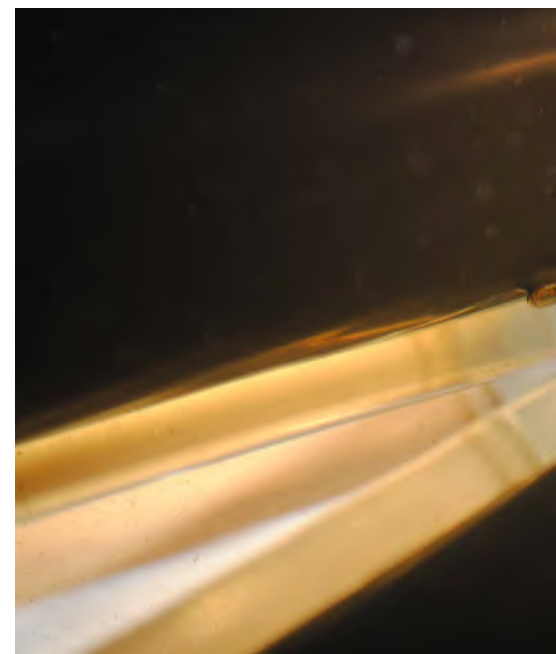
SD insulation fails due to an erosion process associated with a phenomenon called partial discharge (PD). PD is an electrical discharge (or “micro arcing”) that does not completely bridge the insulation. In SD insulation, PD can arise from an extreme focus of electric stress, a lack of the appropriate solid insulation, or a combination of both. Early manufacturing and testing standards were inadequate to prevent subtle and often gross defects from leaving the factory.

The primary cause of cable system failure is human induced damage exacerbated by extreme transient voltage conditions.

In one case in the 1970s, Dr. Matthew Mashikian working for Detroit Edison research lab asked thirteen manufacturers to supply SD cable. Using a modified World War II radio, he performed 60 Hz PD tests and disqualified eleven of the thirteen suppliers. Clearly, cable 100% PD tested in the factory was insufficient for service in the early 1970s. It wasn't until manufacturers learned to improve materials, material handling and the extrusion process that SD cable system reliability started to dramatically improve. Manufacturers learned that even variations as small as a tenth of a millimeter in cable layer interfaces over decades of time can yield electrical stress concentrations, and in some rare circumstances, under

transient voltage conditions yield local stresses 10 kV/mm or higher causing irreparable damage. 40 years later, we now know the problem with aged cable systems has its genesis with manufacturing or installation anomalies that, in some rare cases, can be exacerbated by secondary moisture concentration effects (e.g. water trees and halos).

However, until the early 2000s when the technology to reliably locate defects in the field could illuminate the physics behind cable failure mechanisms, many in the industry missed the origin story and were misdirected to focus on the secondary effects of moisture and conduction – primary issues with PILC cable! There were many efforts to develop tests to detect moisture and chemical solutions to react with it and dry the cable. While tests like tangent delta, dielectric spectroscopy and power factor could detect elevated moisture or conduction levels, they could not detect most defects or locate issues and often produced erroneous values. Chemical injection processes could help dry the cable insulation but could not fix any existing manufacturing or installation defects that still went on to fail cable. While some manufacturers solved their product quality issues sooner than others, by 1990 most of the improvements included in today's cable systems had been implemented and adopted by utility standards. For this reason, the industry typically sees a significant reliability improvement in cable systems installed after 1990.





Common manufacturing defect:
*Protrusion on the inner
semiconducting layer of MV cable as
seen through transparent insulation
during a hot oil analysis*

Today

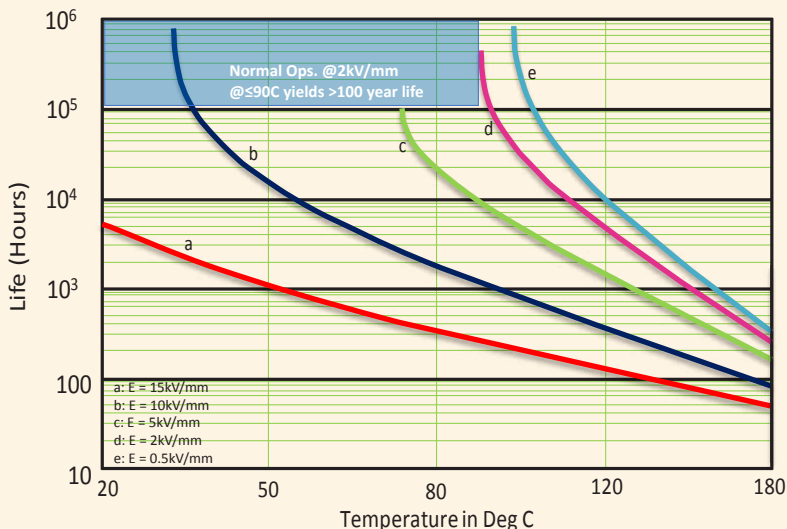
According to one recent study, manufacturing issues constitute a minimum of 5% of cable insulation defects detected in new systems. This means approximately 95% of problems are caused by human intervention during installation. What have we learned and what can we do to avoid the issues of the past and

enable cable systems to last longer? Studies show that the SD materials can perform reliably for over 100 years.

Studies show that the SD materials can perform reliably for over 100 years.

So why are cable systems failing today? On the basis of a study including field assessed meter-

by-meter profiles of over 200,000 new and aged cable systems rated 5 to 500 kV and thousands of field and laboratory dissections, the primary cause of cable system failure is human induced damage exacerbated by extreme transient voltage conditions. Successive transients initialize PD in defects intermittently until the associated erosion process causes failure.

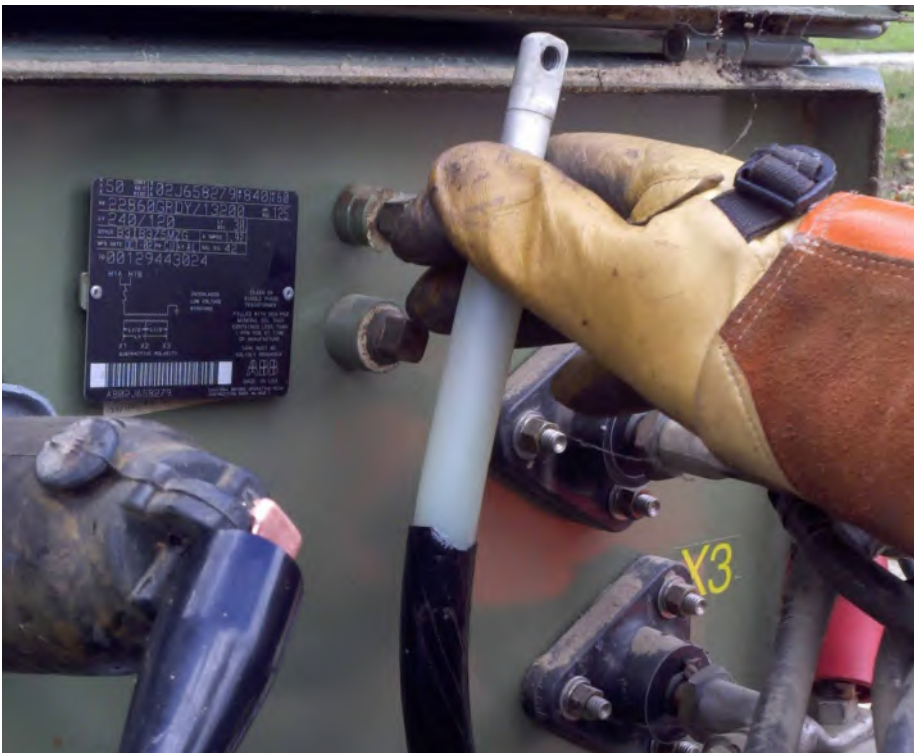


R. Gorur, M. Dyer, Saint, A Novel Approach for Prioritizing Maintenance of Underground Cables PSERC Report 2006

Cable under typical 2 kV/mm stress operated under 90°C lasts longer than 10⁶ or 114 years

Common termination defect:

Jagged outer semiconducting layer cutback



Repeated field tests pinpointing the same defects over multiple years and subsequent laboratory dissections show manufacturing and installation defects often take years and sometimes decades to go to failure.

However, once an aged cable fails, studies show the fault location process, often including intentional voltage transients, creates new defects, thus fulfilling the commonly held belief that cables have a life shorter than 100 years.

So, how can we avoid this cycle of damaging cable systems and drive longevity? We need to avoid introducing defects and extreme voltage stress. How? Consider the following short list of current industry best practices:

- Specify accessory products that are easy to install with large tolerance for installer error
- Train installers to know what a defect looks like and how to fix when a defect is identified
- Commission cable systems with a test comparable to the cable and accessory manufacturers' standards (Overvoltage 50/60 Hz PD test with 5 pC sensitivity)
- Avoid overvoltage tests that do not measure the failure mechanism (PD)
- Ensure proper overvoltage protect (surge arresters) are installed at impedance transitions (overhead to underground transition, branch points, and end points)
- For critical or high ampacity circuits also consider using shear bolt connectors, inspect connector IR signatures under high load conditions, and use ultrasound to detect any significant arcing due to open air termination clearance issues.



The Future

What will cable systems look like in the future? While we cannot predict the future, we can observe trends and extrapolate. Cable system technology has not dramatically changed in the last three decades and will not likely change much in the next decade. However, more and more power system owners are looking at the lifecycle costs of transmission and distribution systems and are choosing underground over overhead. Compared to overhead, underground is on the order of ten times safer and ten times more reliable, can last two to three times longer than wood supported systems, is far more resilient in the face of natural disasters, and the operating and maintenance costs are typically more than three times lower. In the future, where the upfront costs are reasonable, cable systems are likely to be selected as the “ultimate sustainability solution” for power delivery networks. Where feasible, cable systems will likely be directly

buried to enable the best ampacity performance and the lowest upfront and operating and maintenance costs. High-cost duct and vaults systems have some of the highest maintenance costs and yet show no significant reliability improvement over directly buried systems.

Compared to overhead, underground is on the order of ten times safer and ten times more reliable, can last two to three times longer than wood supported systems, is far more resilient in the face of natural disasters, and the operating and maintenance costs are typically more than three times lower.

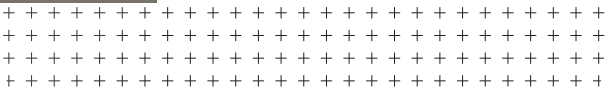
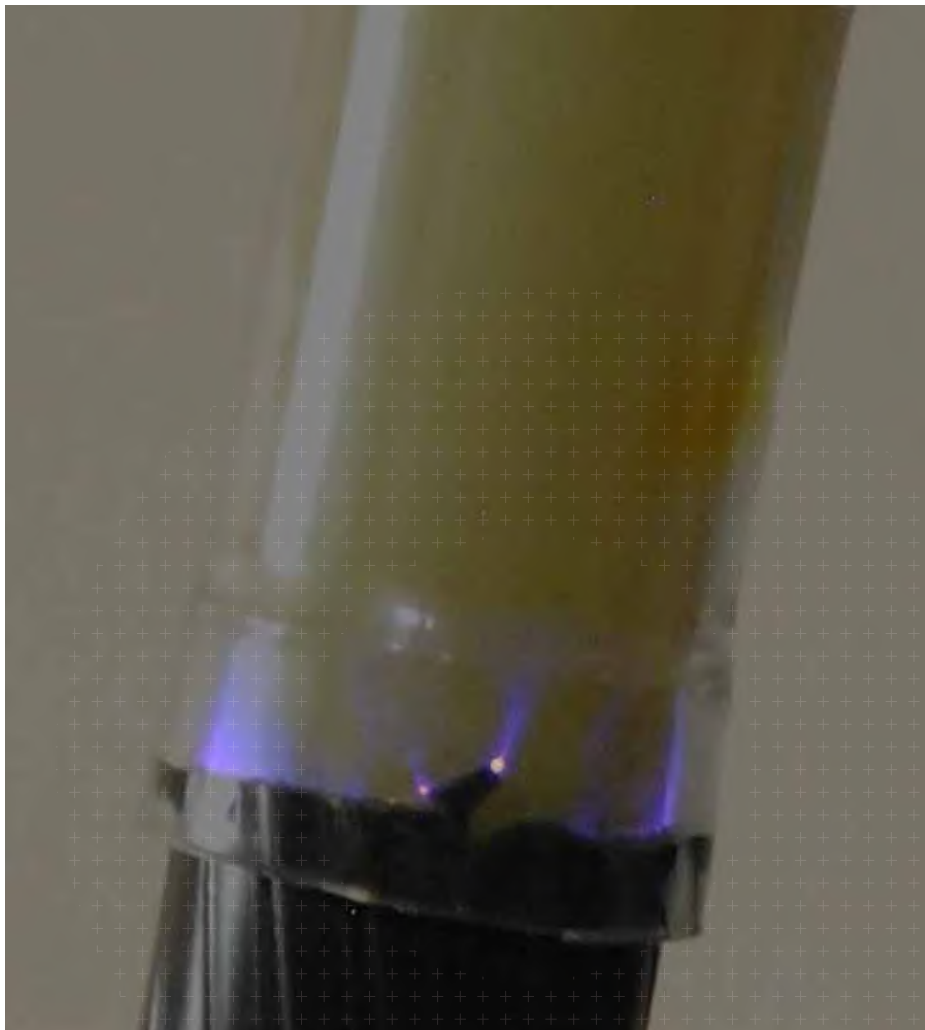
Where the industry will likely see great improvement is in grid reliability performance such as when cable owners take advantage of installer training coupled with effective commissioning tests (as mentioned above) to provide a feedback loop

to improve craftwork and drive out operating and maintenance costs during the capital investment period (installation). Once a cable system is installed, the cable owner will only need to apply maintenance when an extreme event is detected. In the future, data analytics will utilize input from distributed sensors detecting extreme voltage and current events, and data from work orders which indicate potentially damaging mechanical events (such as repairs, relocations, and support structure failures) to drive work orders and direct technicians to re-baseline the cable system using the commissioning test and repair accordingly (see best practices mentioned above).

With modern cable systems properly specified, installed, commissioned, and protected from extreme operational events, the physics indicates we can expect them to last longer than 100 years.

Conclusion

The industry has come a long way from the days of the intensive skill needed to install PILC cable and the poor performance of early vintage solid dielectric systems. Systems are easier to install correctly and more reliable than ever before. We have learned the physics behind cable reliability and longevity, and we no longer need to guess at the failure mechanism. This means we can be much more efficient and precise with specifications avoiding costly partial solutions or risky, ineffective procedures. With modern cable systems properly specified, installed, commissioned, and protected from extreme operational events, the physics indicates we can expect them to last longer than 100 years.





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The step-down system of power grids is what makes transformers so critical from generation to distribution, to power industrial and commercial equipment, and ultimately to light the lights that the world relies upon. In many cases we lose site of the seemingly insignificant control

transformer as we pay attention to the big brother of the transformer family, both fluid filled and dry type.

But control transformers have their own important part to play. Control transformers are transformers that are used to step down the voltage to power the

control devices of a circuit or machine, considering that the reduced voltage provides a much safer environment for technicians working on or around the equipment.

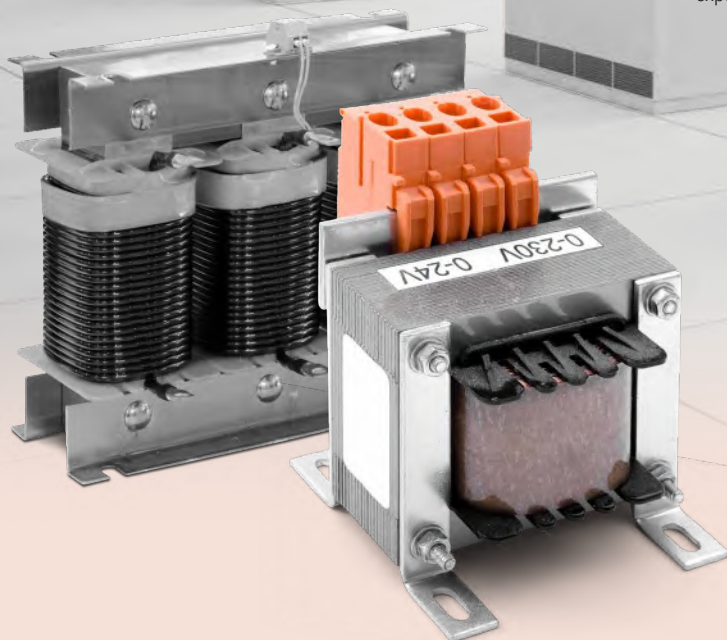
They are also referred to as industrial control transformers, control power

transformers, machine tool transformers and isolation transformers, providing much needed voltage regulation where they are designed to produce a high level of secondary voltage stability during brief periods of overload condition, typically known as inrush current.

Control Transformers



Alan Ross, CRL, CMRP, is the Technical Director of APC Media and the Editor in Chief and Chair of the Technical Advisors Board of Transformer Technology magazine. Alan has decades of experience in the power systems industry and is one of the greatest reliability experts out there.



Additionally, control transformers are used to reduce or eliminate harmonics or transients – power quality issues that can have a significantly negative affect on solid state production equipment, an ever-increasing evolution within the move to “everything digital”.

Growing Demand – Growing Criticality

A recent marketing report indicated that “the industrial control transformer market is expected to grow at a CAGR of around 3.5% over the next decade. Factors such as the increasing number of industries (such

as chemical, and metal and mining), and the demand to reduce equipment failure on account of frequent voltage fluctuations are likely to drive the market, especially in the emerging economies. However, due to the outbreak of COVID-19, slow down, or delay of different industrial projects are likely

to hinder the market growth during the forecast period.”

Now that the effects of Covid seem to be waning, will we see a rebounding effect, where the actual growth rate for the next few years will rebound beyond 3.5%? It is more likely to happen than not to happen.

Applications

Control transformers are most often used in an electronic circuit that requires constant voltage or constant current with a low power or volt-amp rating when power quality issues impact the circuit whether due to harmonics or transients. Capacitors are also used to minimize the variations in the output.

Where electromagnetic devices like solenoid switches or relays are used, especially in industrial applications, the control transformer maximizes inrush capability and output voltage regulation when electromagnetic devices are initially energized.

Control transformers utilize high-quality insulating

materials to insulate turn-to-turn windings; layer-to-layer windings, primary-to-secondary windings; and for grounding. Control transformers are vacuum impregnated with VT polyester resin and oven-cured, which seals the surface and eliminates moisture. The resin creates a strong mechanical bond and offers protection from the environment.



Specification

For proper control transformer specification, three characteristics of the load circuit must be determined in addition to the minimum voltage required to operate the circuit.

These are total steady-state (sealed) VA, total inrush VA, and inrush load power factor as follows:

- Total steady-state (sealed) VA is the volt-amperes that the transformer must deliver

to the load circuit for an extended period — the amount of current required to hold the contact in the circuit.

- Total inrush VA is the volt amperes that the transformer must deliver upon initial energization of the control circuit. Energization of electromagnetic devices takes 30-50 milliseconds. During this inrush period, the electromagnetic control devices draw many times normal current — 3-10 times normal is typical.

- Inrush load power factor is difficult to determine without detailed vector analysis of all the load components. Since such an analysis is typically not feasible, a safe assumption is 40% power factor.

A great example of an isolation transformer in action is the use of power adapters for laptops since there is a difference between the voltage levels supplied to homes and the lower voltage levels required by the laptop itself.

The concept of inrush current can be seen in heavy electricity-powered machinery when the start button is pushed to power a high-voltage motor and the contactor coil is energized. The overload condition is handled far more efficiently by control transformers than a conventional supply, making them efficient power supplies that can be safely used by workers that use start and stop buttons in dangerous work environments.

The control transformer, like the ordinary transformer,



Instrument Transformers

Another type of control transformer is the instrument transformer, which is a general term applied to current and voltage devices used to change currents and voltages from one magnitude to another or to perform an isolating function: to isolate the

utilization current or voltage from the supply voltage for the safety of both the operator and the end device in use.

Instrument transformers are designed specifically for use with electrical equipment falling into the broad category of devices commonly called instruments such as

voltmeters, ammeters, watt-meters, watt-hour meters, protection relays, and more.

Instrument transformers are an important and essential component for safe and efficient operation of transmission and grid networks. They provide accuracy and reliability for the measurement of current and voltage in

secondary equipment, like meters, protection relays, bay computers and a growing number of other devices. They are also used to provide energy to protective relays. Accuracy, the degree to which instrument transformers produce a current or voltage that is proportional to the monitored value, varies among devices.

allows for the transformation of high-voltage electricity from the main circuit into a lower voltage that is used to operate the switching components within the main circuit itself.

If you take a look at a machine that is powered by a 600-volt motor, the contactors used to turn the machine on and off are powered by electro-magnetic coils that operate at voltages that are far lower. In other words, the voltage coming from the main circuit can't be used

in the control circuit. The typical solution would be to install more bus bars or run separate cables through a separate power feed, but anyone with experience will tell you that this option is impractical.

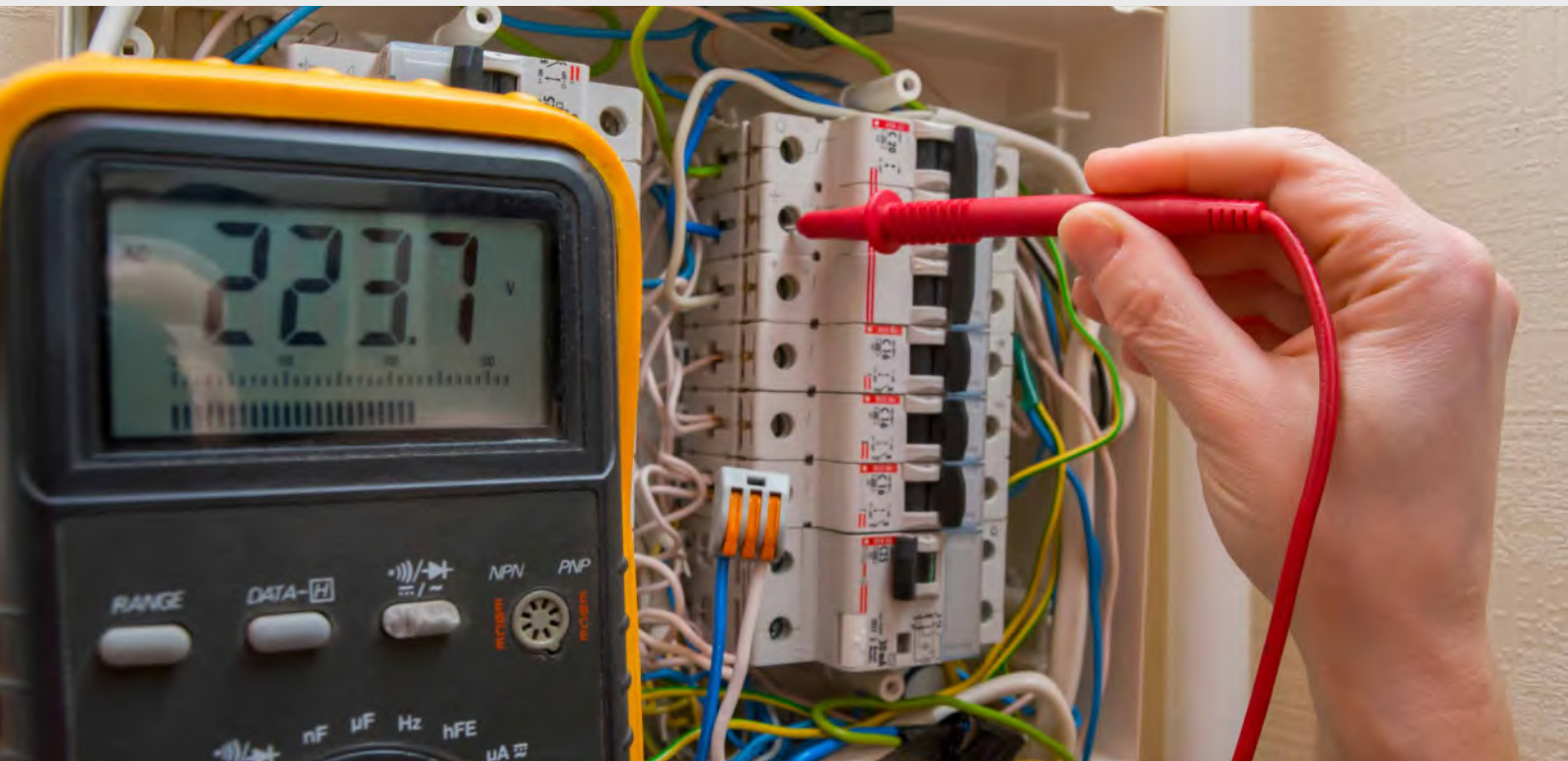
Likewise, it is unsafe to have high voltage electricity flowing through tightly packed wiring with a control panel. The easier and more effective solution is to keep the main circuit voltage and pass it through a control transformer that can then provide the control

circuit with the appropriate amount of voltage.

Control transformers are typically more expensive as they tend to use insulating materials of the highest quality.

For example, some brands sell control transformers that are oven-cured and impregnated with vinyl toluene polyester resin, which allows for the elimination of moisture while keeping the surface sealed and protected from environmental damage.

Most control transformers are sold in a variety of forms, being classified by secondary – 240 primary & secondary, and 480 primary & secondary are just a sample of the variety that is currently available on the market. These transformers are being used in a wide variety of applications that include (but are not limited to) schools, shopping centers, apartment complexes, industrial plants and hospitals.



Conclusion

Control transformers have many names based on their purpose, but they all allow for low control circuit voltage to be safely used in applications where high voltages are required through the supply of control power. The next time you power a heavy-duty construction machine

or anything else that uses high-voltage electricity through a control panel, you will be able to see their magic in action.

The complexity of the future grid is changing as Distributed Energy Resources Management (DERM), the electrification of transportation with the adoption of EVs and efforts

to bring more reliability and resilience to the system, brings the need for more and more complex controls.

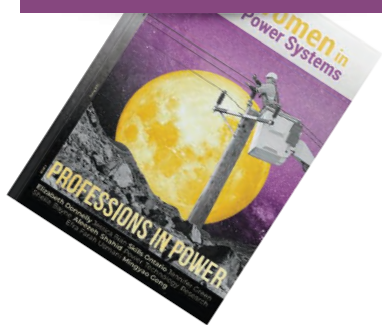
Control transformers, while not considered as important as their "big brothers" – fluid filled or dry type transformers, are an increasingly important part of grid and industrial networks.

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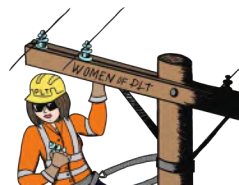
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EFRA FARAH USMANI

Efra F. Usmani is a Team Lead and Project Manager of the E-Mobility Department at Power Technology Research (PTR). As a nature lover and a traveler, she likes to see the role she plays as part of the energy transition that helps preserve the planet.



From childhood, Efra loved Mathematics and Physics. This interest led her to opt for studies of Electrical Engineering at the Lahore University of Management Sciences (LUMS) in Lahore, Punjab, Pakistan. During her studies, Efra found her interest in the power and renewable energy sector and would later do her senior year project on the topic of renewable energy. She served as Vice-President of the IEEE LUMS Chapter in her junior year and as President of the IEEE Power and Energy Society (PES) in her senior year. She was also involved in initiating the first Social Responsibility Program (SRP) of her society along with her twin sister who was working as the President of IEEE Women in Engineering (WIE) LUMS. During her undergraduate years she did internships at the National Transmission and Dispatch Company of Pakistan (NTDC) as well as in the switchgear component manufacturer company Pak Elektron Limited (PEL) and at Telecommunications Company ZONG. She graduated from LUMS in 2019, earning an Electrical Engineering degree with a focus on power and renewable energy. Efra started her professional career as the lead EV charging infrastructure Analyst for the Western and Eastern European markets and in the Power Grid department at PTR. During her time there she worked with some of the biggest Transmission and Distribution (T&D) and E-Mobility clients and was part of projects and research on a global level. At her current position as Team Lead and Project Manager of the E-Mobility Department at Power Technology Research (PTR), she keeps up to date with the latest trends in the industry and enjoys working in this high-impact field of the energy sector. Efra is a big traveler at heart and loves the mountains and rivers of the beautiful Northern areas of Pakistan. She spends her weekends going out and spending time with her family, reading books and watching informative documentaries.

Source:

Efra F. Usmani

How Crucial is HVDC for Energy Transition?

Landscape of HVDC Technology in North America and Europe

by Qutab Baig

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Qutab Baig is a Senior Analyst and Team Leader at Power Technology Research. He manages a team of analysts developing a global knowledge base around several key topics impacted by the energy transition, including High Voltage Direct Current (HVDC) Systems, Flexible AC Transmission Systems (FACTS), Onshore Power Supply (OPS) and Energy Storage Systems (ESS). Qutab has spearheaded several in-house and custom studies for Fortune 500 clients in the U.S. and Europe. By education, Qutab is an electrical engineer with a MS degree in Electrical Engineering.

The world is undergoing an energy transition right now, especially the advanced economies in Europe and North America, in line with the Net-Zero targets and commitments made at the regional and international level. Within the energy sector, the debate is usually highly focused on power generation and the shift to cleaner resources, however, the transmission facilities, which are key enablers in evacuating this power to achieve desired transition, are often overlooked.

Globally, there are more than 350 installed and upcoming HVDC projects, spread around the world.

One of the key elements within this infrastructure are the long-distance transmission lines. Historically, electricity over long distances has been transmitted through HVAC

transmission lines and facilities, however, with the evolution of power electronics coupled with the need to integrate more and more renewables in the grid, HVDC transmission systems have also been regularly installed around the world.

The installations of HVDC systems can be segmented into three main applications: bulk power transmission, interconnecting grids, and infeed urban areas. HVDC systems are a popular choice for cross border interconnections. For instance, submarine cables are being installed to transmit power across regions and countries along with overhead HVDC lines, e.g. BritNed or Sardinia-Italy Mainland connections. These systems are best suited for supplying electricity to densely populated urban areas where significant obstruction could be caused by the density of overhead lines. One of the fastest growing applications of HVDC has been the offshore wind connection with the grid.

One of the fastest growing applications of HVDC has been the offshore wind connection with the grid.

Globally, there are more than 350 installed and upcoming HVDC projects, spread around the world, with the largest number of them being in APAC, followed by Europe and North America. This article will focus on two of these regions: North America and Europe.

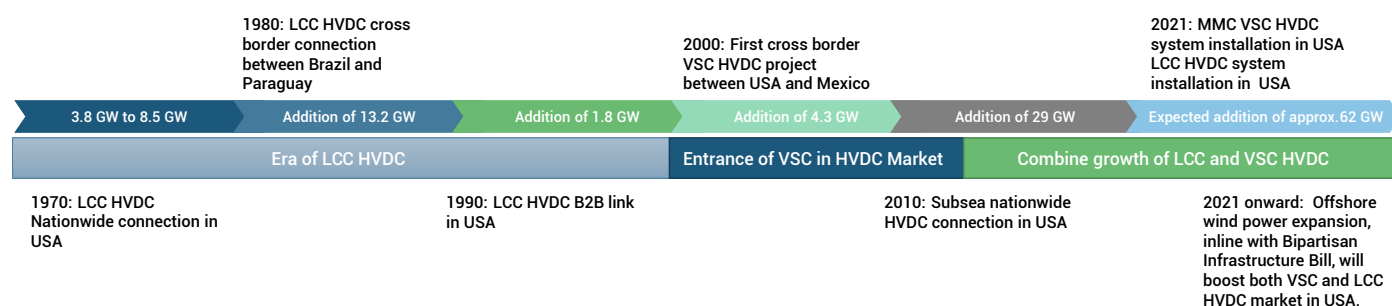


Figure 1. Timeline of deployment HVDC technology in the US (Source: Power Technology Research)

HVDC Market in North America

The North American HVDC transmission market is largely driven by the U.S. and Canada where sweeping majority of the region's HVDC transmission capacity is installed. Region's overall HVDC transmission capacity accounts for more than 32 GW, with LCC HVDC projects dominating the installed capacity. Figure 1 gives a brief timeline of key HVDC projects installed in the US.

Within North America, the U.S. current HVDC transmission capacity is around 20 GW. LCC HVDC technology is leading the market in the country with the majority of HVDC interconnections being nationwide,

and with a few cross-border interconnection with neighboring countries. Canada, on the other hand, has a current HVDC transmission capacity of around 12 GW. The HVDC market in Canada experienced a boom in 1980s and in the last decade when majority of nationwide HVDC interconnection commenced their commercial operations. The Canadian HVDC market has been dominated by LCC HVDC, with the first VSC HVDC system, installed by ABB, starting its commercial operation in 2018. Beyond the U.S. and Canada, other markets in the region have very small installed capacities: e.g. Mexico has only one LCC project (Railroad DC Tie) with a capacity of 300 MW connecting Mexican national grid to ERCOT.

HVDC Technology Split in North America

Overall, the HVDC transmission market of the North American region is dominated by LCC HVDC technology. However, in the coming years, with the expansion of renewables, particularly offshore wind farms, more VSC HVDC systems are proposed by TSOs to enhance the reliability and transmission capacity of the transmission grid.

Until 2000, an overwhelming majority of the HVDC transmission systems installed in the region were LCC HVDC systems accounting for 95% of the total installations, whereas only 5% of the systems were VSC HVDC systems. From 2000 to 2010, majority

of the projects installed were still LCC HVDC systems accounting for 71% of the total projects installed, but VSC HVDC technology gained traction accounting for 29% of the installed projects. In the last 10 years, the trend has been similar, with 67% of the projects installed being LCC HVDC systems, followed by VSC HVDC projects accounting for a slightly more than 33% of the total projects installed (Figure 2).

The U.S. has a 25.4% share of renewables in the generation capacity mix and is planning to reach 80% of the capacity mix by 2030.

HVDC Market Drivers in North America

The renewable energy targets, specifically the planned expansion of offshore wind along with the proposed legislation (if approved) and the loan guarantees from the Department of Energy for transmission projects in the U.S., will be the primary drivers of HVDC demand in North America.

The U.S. has a 25.4% share of renewables in the generation capacity mix and is planning to reach 80% of the capacity mix by 2030. On the other hand, Canada is already targeting to reach 90% renewables (including Hydro) by 2030. A big part of these targets is expected to be met through offshore wind energy. In the U.S., New York, Massachusetts, New Jersey, Maryland, and Virginia will be spending around USD 55 billion on 15 offshore wind energy projects in the next ten years, with the overall country-wide target of 30 GW offshore by 2030 set by Biden's administration. Most of these projects will be connected to the power grid using HVDC transmission interconnections, possibly funded via Electric Power Infrastructure Improvement Act or US DOE's Loan Program Office.

HVDC Market in Europe

Across the Atlantic in Europe, Germany,

U.K., Italy, Denmark and France have the highest HVDC transmission capacity. The region has a cumulative HVDC transmission installed capacity of around 43 GW, with Germany leading the region in terms of installed HVDC transmission capacity, followed by U.K. and Italy.

Germany has an installed HVDC transmission capacity of 11.25 GW of electricity. German HVDC system in spread not only within the country itself, but also has interconnections with neighboring countries including Switzerland, Belgium, Sweden.

In the U.S., New York, Massachusetts, New Jersey, Maryland and Virginia will be spending around USD 55 billion on 15 offshore wind energy projects in the next ten years, with the overall country-wide target of 30 GW offshore by 2030 set by Biden's administration.

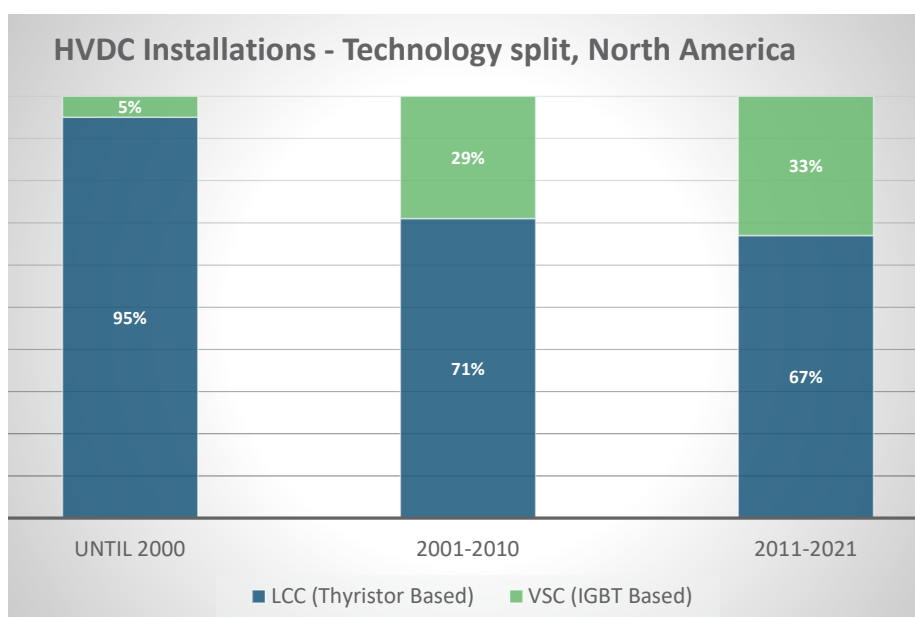


Figure 2. HVDC installations in North America (Source: Power Technology Research)

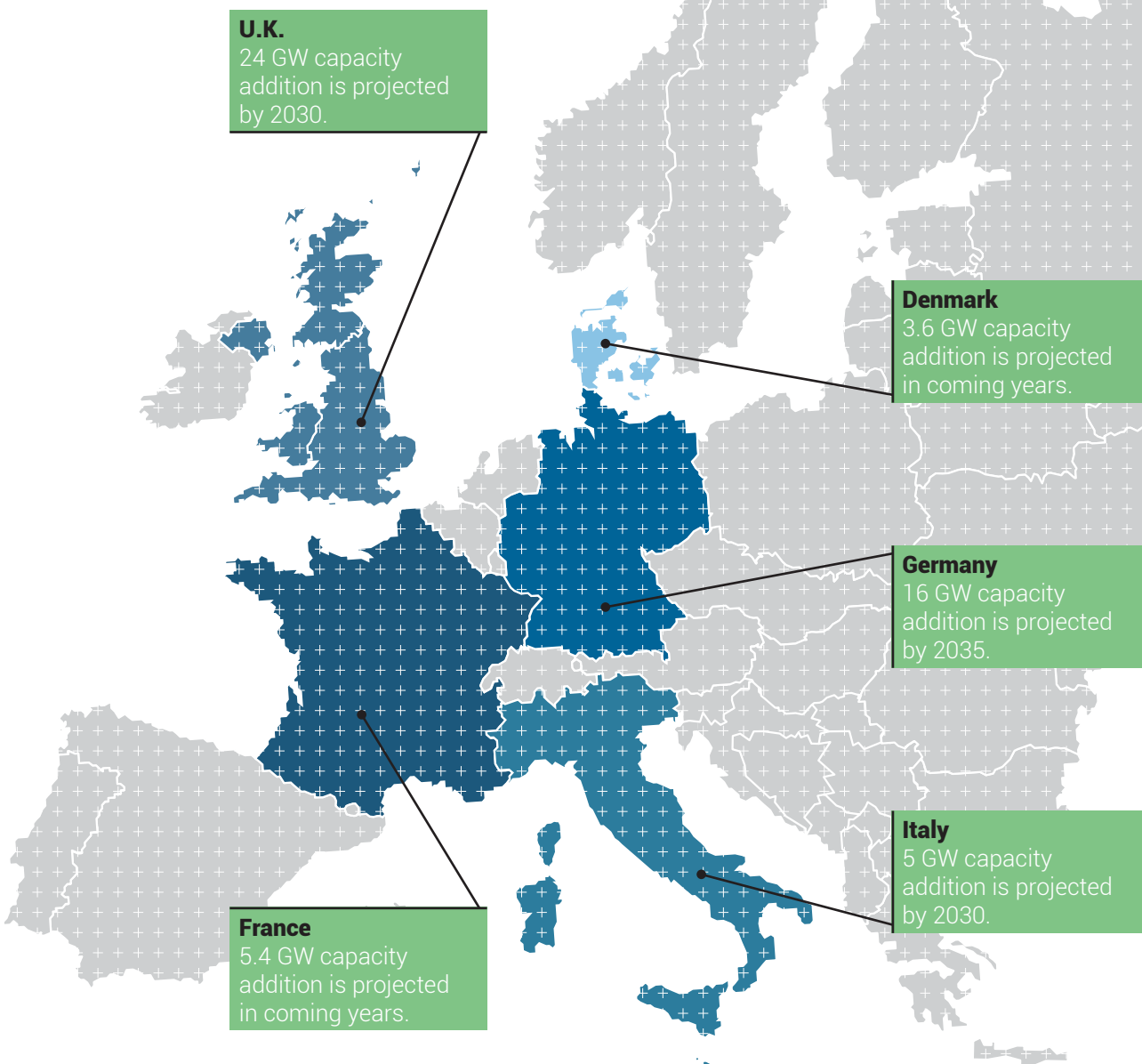


Figure 3. Top five HVDC markets in Europe (Source: Power Technology Research)

U.K., with the second largest installed capacity, hosts 6.4 GW of HVDC transmission capacity and the country has several cross border HVDC interconnections with France, Netherlands and Norway. However, the country is continuing to expand the transmission capacity through new HVDC projects to transmit electricity from the offshore wind farms in the North Sea back to shore. Italian HVDC transmission network has the capacity to deliver 3.7 GW of electricity from the generation center to load centers in the country. Italy also has a couple of cross-border HVDC projects connecting the Italian grid with grids of France and Montenegro.

HVDC Technology Split in Europe

The majority of the HVDC systems installed in Europe between mid-1970s and 2000 were thyristor based LCC HVDC systems. From 2001 to 2010, however, the VSC IGBT systems market experienced a substantial growth in the region as these systems provide a quick switching response compared to LCC Thyristor HVDC systems. VSC IGBT systems and LCC Thyristor systems accounted for 56% and 44% of the new installations respectively between 2001-2010. From 2010-2020, 72% of the installations in the region were VSC IGBT based while only 28% were LCC Thyristor based installations.

HVDC Market Drivers in Europe

Europe has set ambitious renewable energy targets, whose realization will provide a significant boost to the demand of HVDC transmission systems. Several regulations are in force in the E.U., such as the renewable energy directive and national renewable energy action plans, which are key driving factors in the transition to a low-carbon energy system. Europe is striving to become the first carbon neutral continent by 2050 and the targets have been set accordingly for deployment of renewables in the region. European Union has set a target of installing at least 60 GW of cumulative offshore

wind by 2030 and 300 GW of cumulative offshore wind capacity by 2050.

Moreover, the European Commission's directive has set a target of at least 10% interconnection capacity by 2020 and 15% interconnection capacity by 2030 to transmit electricity to neighboring countries. As the region pursues offshore wind energy targets along with the increase in the interconnection capacity, HVDC systems are expected to play a crucial role in transmitting this power in the continent.

Europe is striving to become the first carbon neutral continent by 2050 and the targets have been set accordingly for deployment of renewables in the region.

Moving Forward

The HVDC transmission is vital technology to connect these renewable energy generation centers with the load centers or onshore grid infrastructure. With the growing trend of renewable energy deployment throughout the world, the HVDC industry is gaining pace. Rollout of renewable energy resources, especially the offshore wind energy segment within the

renewable category, along with the increasing cross-border connections within the E.U. and between the U.S. & Canada, will continue driving the demand for HVDC systems in these two regions.

The recent developments in the E.U. indicate that there is a huge potential for deployment of renewables which will give boost to the market of HVDC transmission systems needed to transmit power over long distances. Development of offshore wind power plants specifically is gaining a lot of traction in the North Sea and Baltic Sea regions, which will in turn provide a push to the HVDC transmission systems market in the region. Germany alone is planning to add around 16 GW of HVDC transmission capacity by 2035 focused on strengthening their nationwide HVDC infrastructure along with cross-border HVDC interconnections with Norway, Switzerland and Italy.

In North America, majority of the activity in the HVDC transmission systems market in the coming years will be seen in the U.S., which plans to install around 39 GW of HVDC transmission capacity till 2030. VSC HVDC systems are expected to overtake the LCC HVDC systems market as they provide a higher response rate suitable to integrate

the power generated by offshore wind farms in the load centers. Canada is expected to install 4 GW of HVDC transmission capacity in the coming years, majority of which will be cross-border HVDC transmission capacity needed to import clean electricity to Canada from the U.S.

The U.S. is planning to install around 39 GW of HVDC transmission capacity by 2030.

After a relative slowdown in new projects over the last couple of years, both regions are expected to grow significantly for the next few years, with sustained demand especially for IGBT based VSC HVDC systems. It is certainly important to keep a close eye on tenders and market developments, if your business is in any way related to HVDC technology.

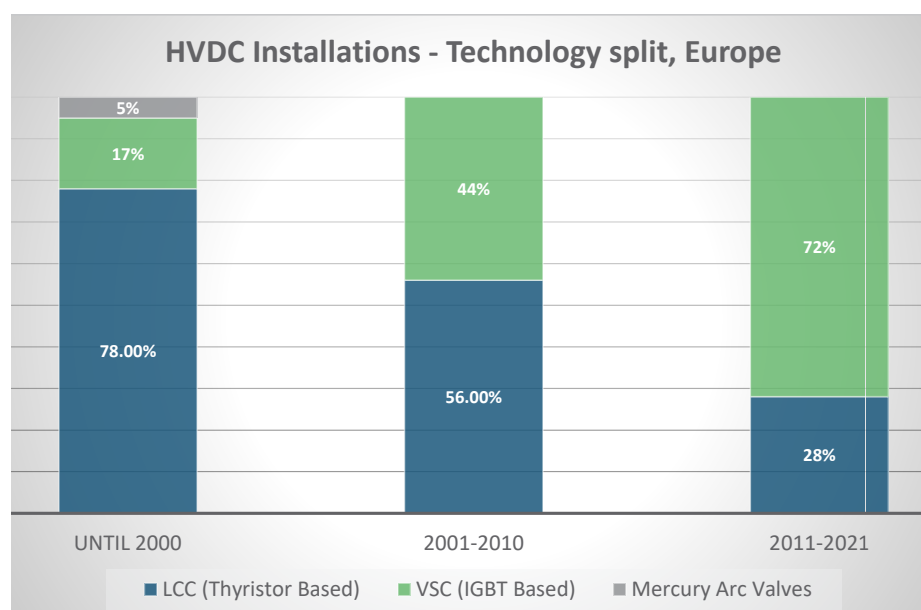


Figure 4. HVDC installations in Europe (Source: Power Technology Research)

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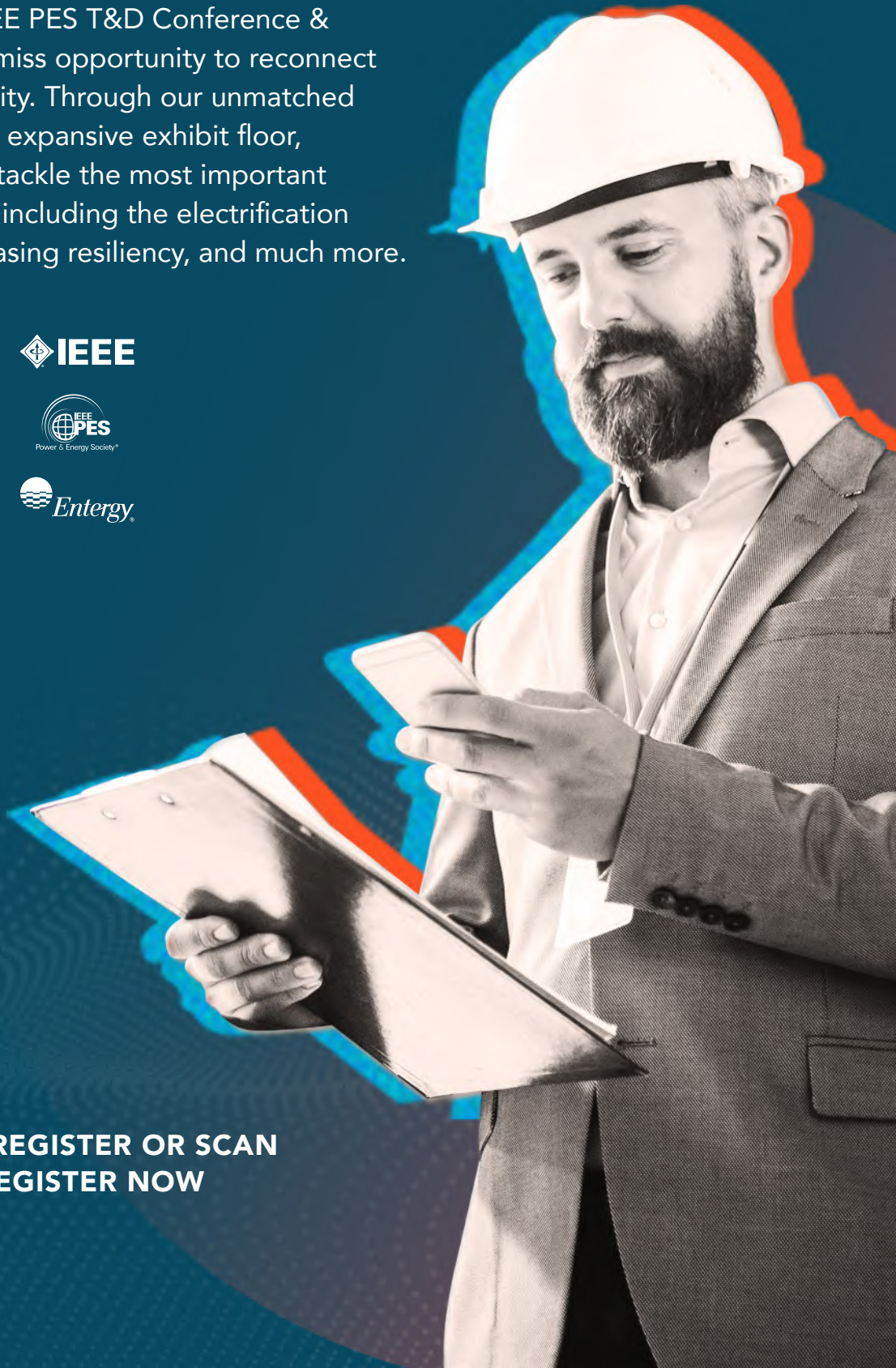
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Transformer Connections: Types and Their Impact on System Performance

by **Ed Khan**

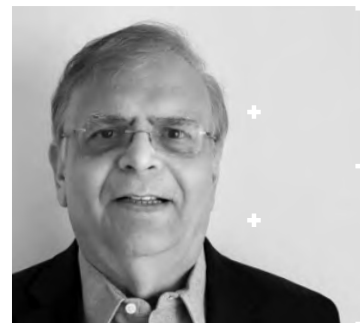
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Transformers are connected in various configurations, some of which are delta/wye, wye/wye and wye/delta. Transformer connections have an impact on a number of criteria of system performance, including the following:

1. Phase shifts impact relay protection and system operability

2. Neutral grounding of wye connected winding impacts ground relaying and overall system performance



Ed Khan is the Director of Protection R&D and Protection Training at Doble Engineering, where he manages and conducts relay protection training program. He has been with Doble for 14 years working in various capacities including Product Manager for protection tested related instruments. Prior to Doble, Ed worked for GE, ABB, SEL, KEMA and other companies in various capacities. He has 38 years of experience in power systems. Ed has a master's in electrical engineering obtained from Texas A&M.

3

3. Flow of ground fault current impacts relay protection and system performance

4

4. Passage of third harmonic current is needed to produce sinusoidal transformer output voltage

5

5. Connections enabling twelve pulse rectification

Impact on differential protection

One of the impacts is related to transformer differential protection. To understand this impact, we must review the phase angle shifts that result from various connections.

Figure 1 shows the wye-wye connection. In this connection the primary and secondary currents, in all phases, are in phase and hence there is no need for compensation.

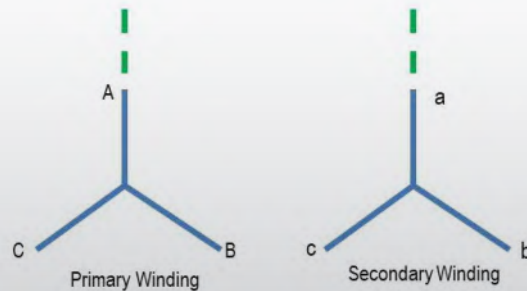


Figure 1. Wye-wye connection

Figure 2 shows the delta-wye connection (which can also be wye-delta). In this connection the primary and secondary currents in all phases are not in phase. There is a 30-degree phase shift and hence, a compensation is needed. This compensation is performed through current transformer connections, or, internally, in a microprocessor differential relay.

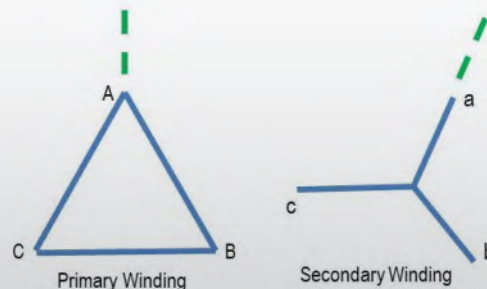


Figure 2. Delta-wye connection

Figure 3 shows common transformer connections that are in use. The phase shifts are designated in terms of hour positions on a clock. For example, Dd0 means that the primary and the secondary current are in phase with A phase of windings at 12 o'clock or zero hours.

Similarly, DY1 connection means that the primary winding is connected in delta with A phase pointing at 12 o'clock and the secondary winding is connected in wye with A phase pointing towards 1 o'clock, resulting in a phase shift with wye winding lagging delta winding by 30°.

If we look at a three-winding transformer, a connection designated as YNy0d1 means that the primary is wye grounded at 12 o'clock and the secondary winding is wye ungrounded also set at 12 o'clock or zero hours. The delta tertiary is shifted towards 1 o'clock resulting in a phase shift of thirty degree from the wye windings. The letter N or n stands for grounded neutral.

Some possible transformer connection

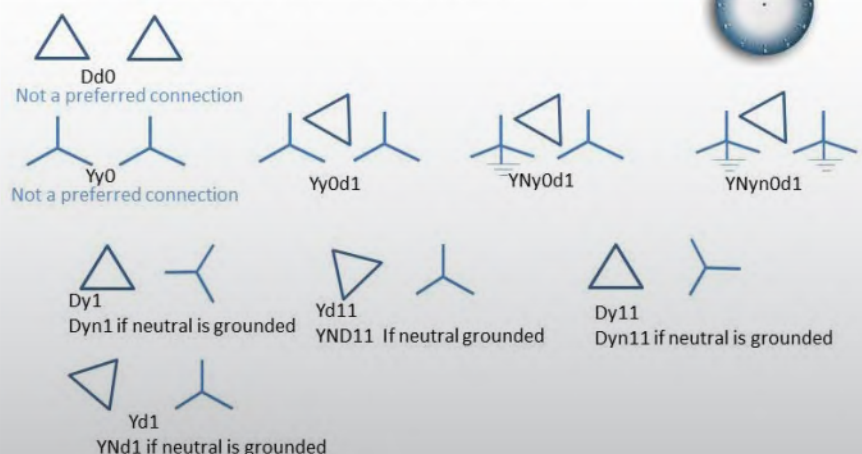


Figure 3. Common transformer connections



Phasing issues

Transformer connections can lead to phasing issues which can be solved by using appropriate winding connections.

Figure 4 shows a layout at a typical powerplant. Transformer T5, which has been circled in the diagram, feeds the auxiliary load. When the generator is started and brought online, the power to the auxiliary bus is fed by transformer T6. Breakers B and T are in close position and breaker A is open. The auxiliary bus feeds motors and other loads that are necessary to support the generator. Once the generator is synchronized, breaker A is closed followed by opening of breaker B. Hence, the two sources fed by breakers A and B are paralleled for a short duration. Hence, the output of transformer T5 and T6 should be in phase. To achieve this, the transformer T5 has to be of certain connection, as shown in Figure 4. If the generator step up is connected as YNd1, T5 will have to be connected as DYn11.

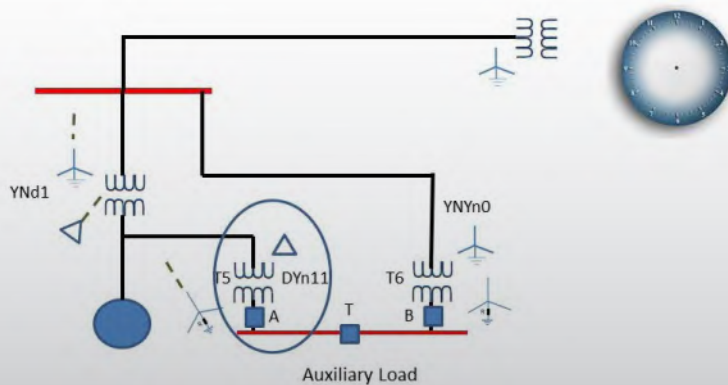


Figure 4. A typical powerplant layout

Shifting of transformer damage curve

Figure 5 shows a delta-wye transformer with neutral grounded. In the event of a line to ground fault on the wye side of the transformer, the ground relays on the delta side will not see this ground fault. This is due to infinite zero sequence impedance between the two windings. However, the phase relays will see this as a phase-to-phase fault with magnitude diminished to 58% of what it would see if there were a three-phase fault on the wye side. The transformer damage curve, which represents the capability of the transformer to withstand a through fault is plotted for a three-phase fault. In effect, the phase relays on the delta side are seeing only 58% of the current and hence will not trip in time to protect the transformer. Hence, the solution is to shift both the damage curve and the characteristics of the phase relay by 58% towards the left. In effect, the setting for the phase overcurrent relay needs modification.

The damage curve has to be shifted 58% to the left for delta wye transformer

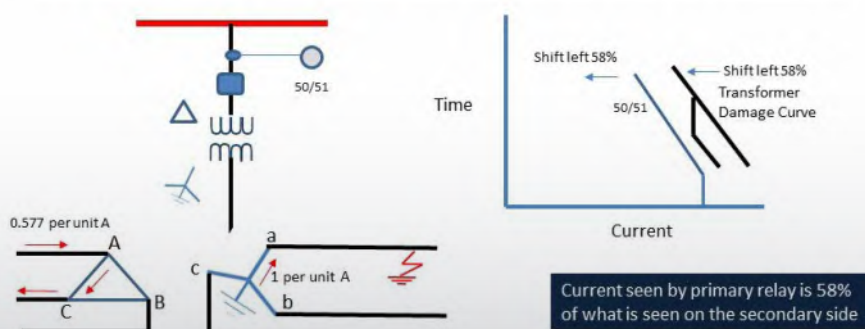


Figure 5. A delta-wye transformer with neutral grounded

Managing the flow of third harmonic

Excitation current required by transformers is between 1-5% of the rated current of the transformers. The excitation current contains 60 Hz along with few harmonics. Most prominent harmonics are the 3rd, 5th, 7th, 9th, and 11th. The 3rd harmonic, which is most prominent, requires special attention. To understand the issue, we must understand the characteristics of this harmonic.

Figure 6 shows the sequence of the 1st through 3rd harmonic. The first, second and third harmonics exhibit positive, negative and zero sequence characteristics, respectively. Using the first harmonic phase angles as reference, we obtain the sequence angles for 2nd and 3rd harmonics by multiplying the 60Hz angles by two and three, respectively. As shown Figures 6 and 7, the 2nd and 3rd harmonics exhibit characteristics of negative and zero sequence, respectively.

Similarly, the 4th, 5th and 6th harmonics are positive, negative and zero sequence and likewise 7th, 8th and 9th harmonics are also positive, negative and zero sequence.

In Figure 7 we observe that the vector addition of I_A , I_B , and I_C for both positive and negative sequences result in a sum of 0 because of 120° separation. Hence, there is no current at the neutral to flow back to another available neutral. This is not the case with the 3rd, 6th, and 9th harmonics. These are zero sequence harmonics and the summation at the neutral is three times the current in each phase. The 3rd, 6th and 9th harmonic will flow if there is either a delta winding or a close path through ground. In short, the zero sequence harmonics need a closed path. This is explained in Figure 8.

Furthermore, in the case of wye-delta connection as shown in Figure 8, the 3rd harmonic line-neutral emf will force a third harmonic current in the delta which forms a close loop.

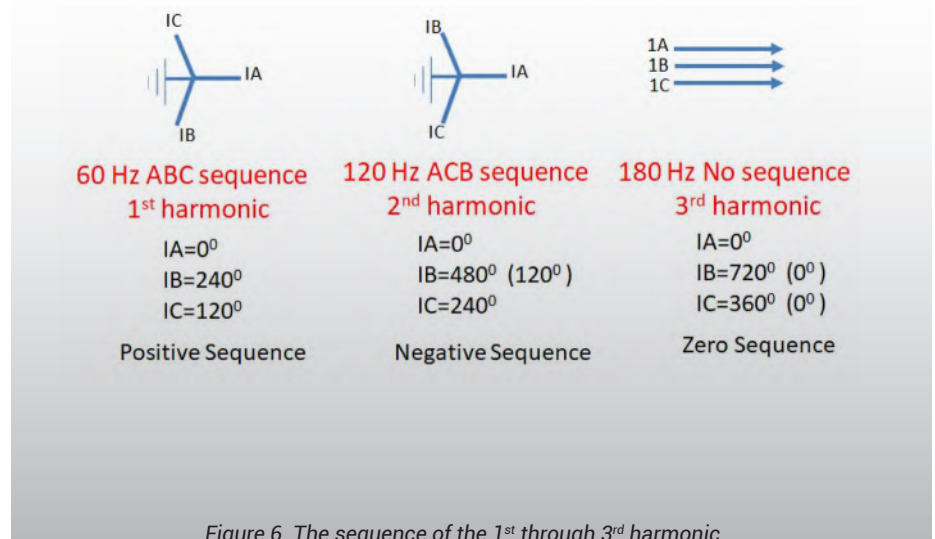


Figure 6. The sequence of the 1st through 3rd harmonic

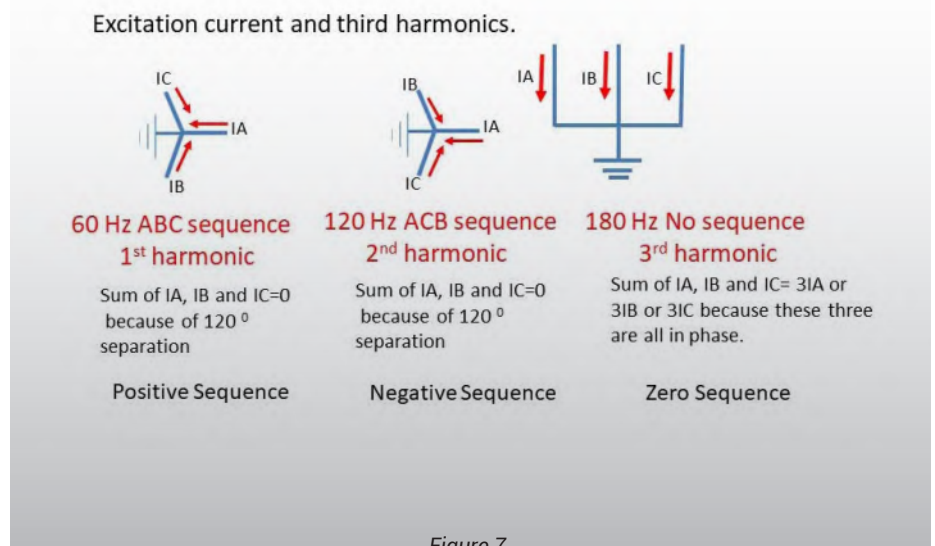


Figure 7.

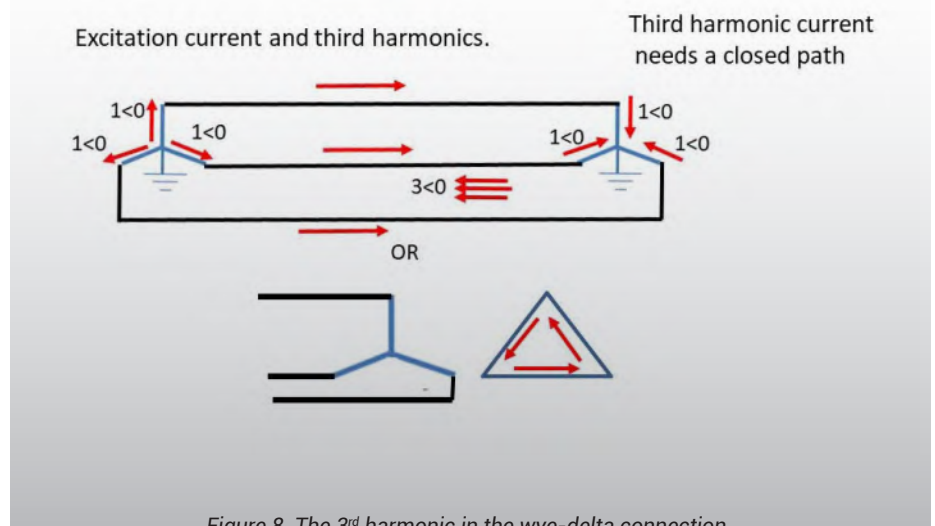


Figure 8. The 3rd harmonic in the wye-delta connection



There is no need for 3rd harmonic current to flow in the wye winding. Additionally, there is no line-to-line 3rd harmonic emf present because the 3rd harmonic currents are all in phase.

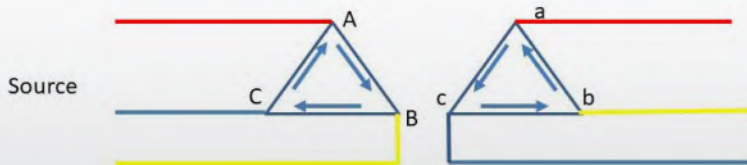
Figure 9 shows a delta-delta connection. This connection is not a preferred option for various reasons. However, this connection does provide a closed path for the third harmonic to flow.

Figure 10 shows a wye-wye configuration for a transformer. The source supplies the excitation voltage, which contains 3rd harmonic line-neutral voltage. This voltage is impressed on primary winding of the transformer. However, there is no closed path for the third harmonic to flow. Third harmonic current must be allowed to flow to eliminate any third harmonic voltage in the transformer output voltage.

If the transformer is core type, third harmonic current will flow since in a core type transformer the winding layout creates a fictitious delta tertiary. If it is a shell type, a delta tertiary will be required unless the neutral of the source and the neutral of the transformer primary are grounded. However, the grounding of these two neutrals is not preferred since the flow of 3rd harmonic between the two neutrals will cause interference with communication circuits.

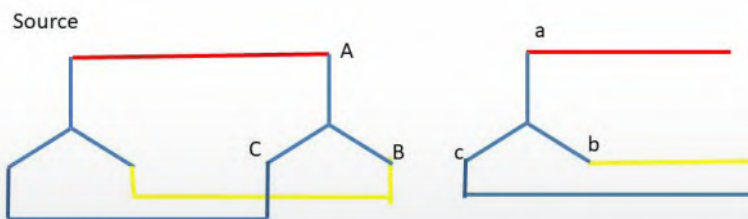
One exception related to zero sequence harmonic (3rd, 6th, 9th) as opposed to 60 Hz zero sequence is that the flow of these triplen harmonic currents do not follow the balancing ampere turn rule. This means that a current flow in one winding does not require a flow of current in the other winding. In other words, balancing the ampere turns is not required.

The wye-wye connections with neutrals ungrounded as connection shown in Figure 10 has other issues such as neutral instability, overvoltage, etc. and hence is not preferred unless the transformer has a core type winding.



Third harmonic has a closed path to flow. However, this is not a preferred connection for various other reasons.

Figure 9. A delta-delta connection



Third harmonic has no closed path.

Figure 10. A wye-wye configuration

In the case of a shell type transformer, a tertiary winding is definitely used. Figure 11 shows a shell type transformer and this connection will allow third harmonic current to flow and suppress the 3rd harmonic voltage in the transformer output voltage. If this was a core type transformer, the third harmonic will flow without the delta tertiary since the core type winding creates a fictitious delta tertiary.

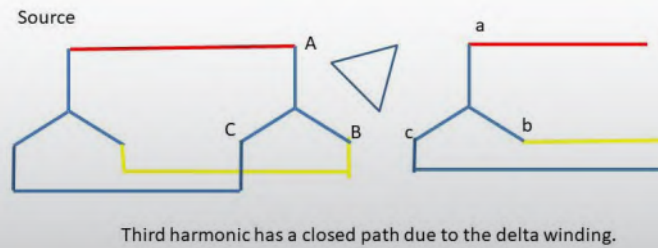


Figure 11. A shell type transformer

Figure 12 shows a case where the transformer is connected in wye-wye with system neutral grounded and the primary of the transformer grounded. In this case 3rd harmonic will flow in the wye primary winding. However, the flow of harmonic between the system neutral and the transformer primary neutral will result in interference with communication system.

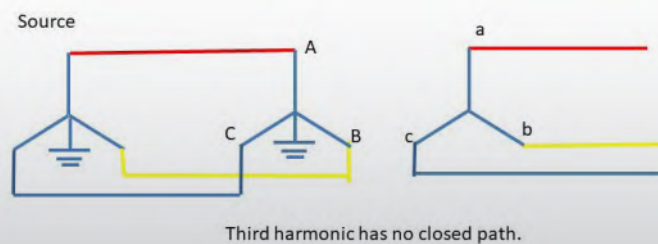


Figure 12. A wye-wye connected transformer with system neutral grounded and the primary of the transformer grounded.

In this case if there is a delta tertiary in addition to the grounding of neutrals as shown in Figure 12, the 3rd harmonic will split between the primary winding and the delta winding and this split is of no concern.

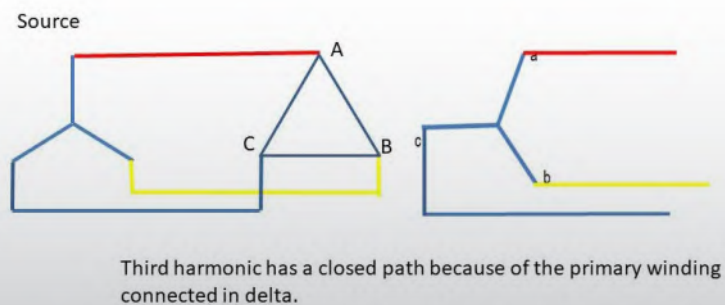


Figure 13. Best connection for allowing the flow of 3rd harmonic.

Figure 13 shown below is the best connection for allowing the flow of 3rd harmonic. The 3rd harmonic emf is impressed on the delta winding and resultant 3rd harmonic flows in the delta winding.

There is no need for corresponding 3rd harmonic to flow in the secondary winding since balancing ampere turns is not required as far as 3rd, 6th, 9th harmonics are concerned.

Figure 14 shows the same configuration as Figure 13 except the primary winding is connected in wye and the secondary winding is connected in delta. In this case also the 3rd harmonic current has a closed path to flow within the delta.

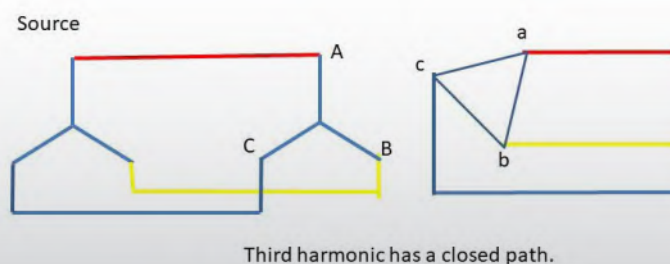


Figure 14. Same as Fig. 13 but here the primary winding is connected in wye and the secondary winding is connected in delta.



Connections for Generator Step up Transformers (GSU)

One of the factors that influence the selection of transformer connection is the flow of ground fault current through the transformer. Connections can either allow or block the flow of ground fault currents between two parts of the system connected via transformer. One critical area requiring careful attention is the selection of transformer connection for GSUs.

Figure 15 shows the GSU connected grounded-wye/grounded-wye. This connection is not desirable because the magnitude of ground fault flowing in each winding is indeterminant during a ground fault on either side of the GSU. This connection makes it difficult to determine proper settings for ground protection relays.

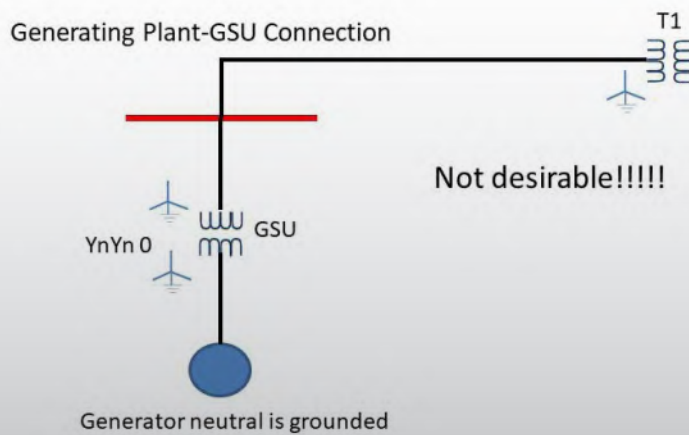


Figure 15. A GSU connected grounded-wye/grounded-wye

If this GSU is of shell type design, it will contain a tertiary winding. Presence of tertiary winding will complicate ground fault relay protection even further. In short, determination of current distribution between the two grounded system is difficult.

If the GSU is core type design, a physical tertiary is not required. A core type transformer by design creates a fictitious delta tertiary. With the connection as shown in Figure 15, ground relaying becomes complicated whether it is shell or core type design.

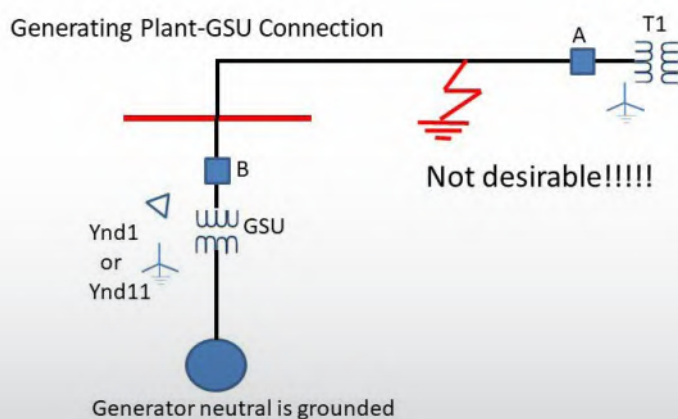


Figure 16. A GSU connected in delta on the high side and wye grounded on the generator side

Figure 16 shows the GSU connected in delta on the high side and wye grounded on the generator side. This is not a desirable connection for the GSU.

A ground fault between on the line connecting GSU and transformer T1 will be cleared by breaker A. However, the wye side of the transformer will not see this fault and hence breaker B will not trip. The grounded conductor will remain connected to the generator and hence will be live. It is a safety issue and furthermore if there is distribution circuit tapped off the line, the generator will supply an ungrounded system. This is an unacceptable situation.

One solution is to install a grounding bank on the high side of GSU as shown in Figure 17. This will provide a path for the ground fault current to flow through the grounding transformer. This will enable tripping of breaker B via relay applied in the neutral of the grounding bank.

Figure 18 shows a desirable connection. Ground faults in the transmission line will be cleared by breakers A and B. Ground faults on the generator side will be cleared by tripping breaker B via ground relays applied at the generator. The generator neutral is grounded.

The role of transformer connection in rectification

Figure 19 shows an adjustable speed drive system utilized in industrial plants to power adjustable speed motors. There is rectification followed by inversion of DC current into adjustable 60 Hz power to the motor.

Commonly used schemes are 6 pulse and 12 pulse. Figure 14 shows a 12-pulse rectification using twelve diodes/thyristors. The disadvantage of cheaper option 6 pulse scheme is two-fold. The DC output is not smooth, and the rectification creates significant harmonics that are injected into the incoming AC power supply. The two main harmonics that create voltage and current distortions are the 5th and the 7th harmonics.

The issue of DC current quality is solved by using a more expensive option of 12-pulse rectifier, which uses 12 diodes/thyristors scheme. The issue of harmonic distortion is solved by introducing a 30-degree phase shift between the two secondary windings as shown in Figure 19. Due to proper selection of transformer connection, a 30-degree phase shift is achieved resulting in significant reduction in harmonics injected into the incoming AC power supply.

Generating Plant-GSU Connection

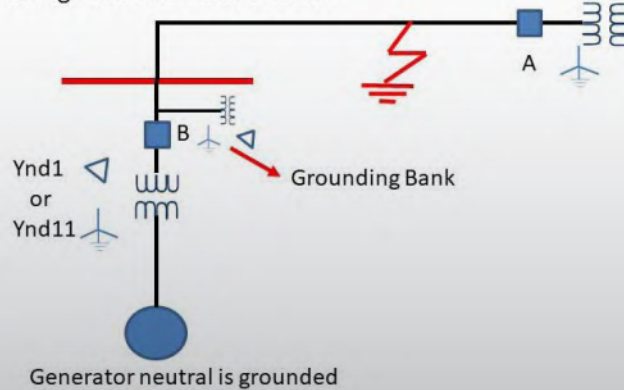


Figure 17. A grounding bank on the high side of GSU

Generating Plant-GSU Connection

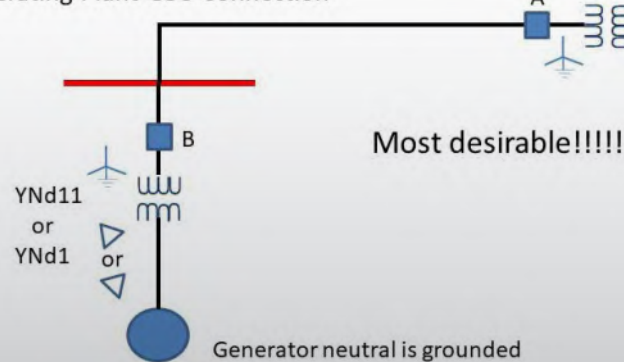


Figure 18. A desirable connection for a GSU transformer

Impact on Rectification—Phase shift of 30 degrees makes this a 12 pulse rectification

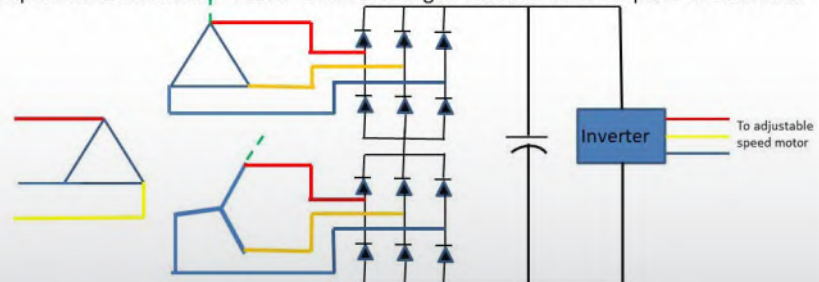


Figure 19. An adjustable speed drive system



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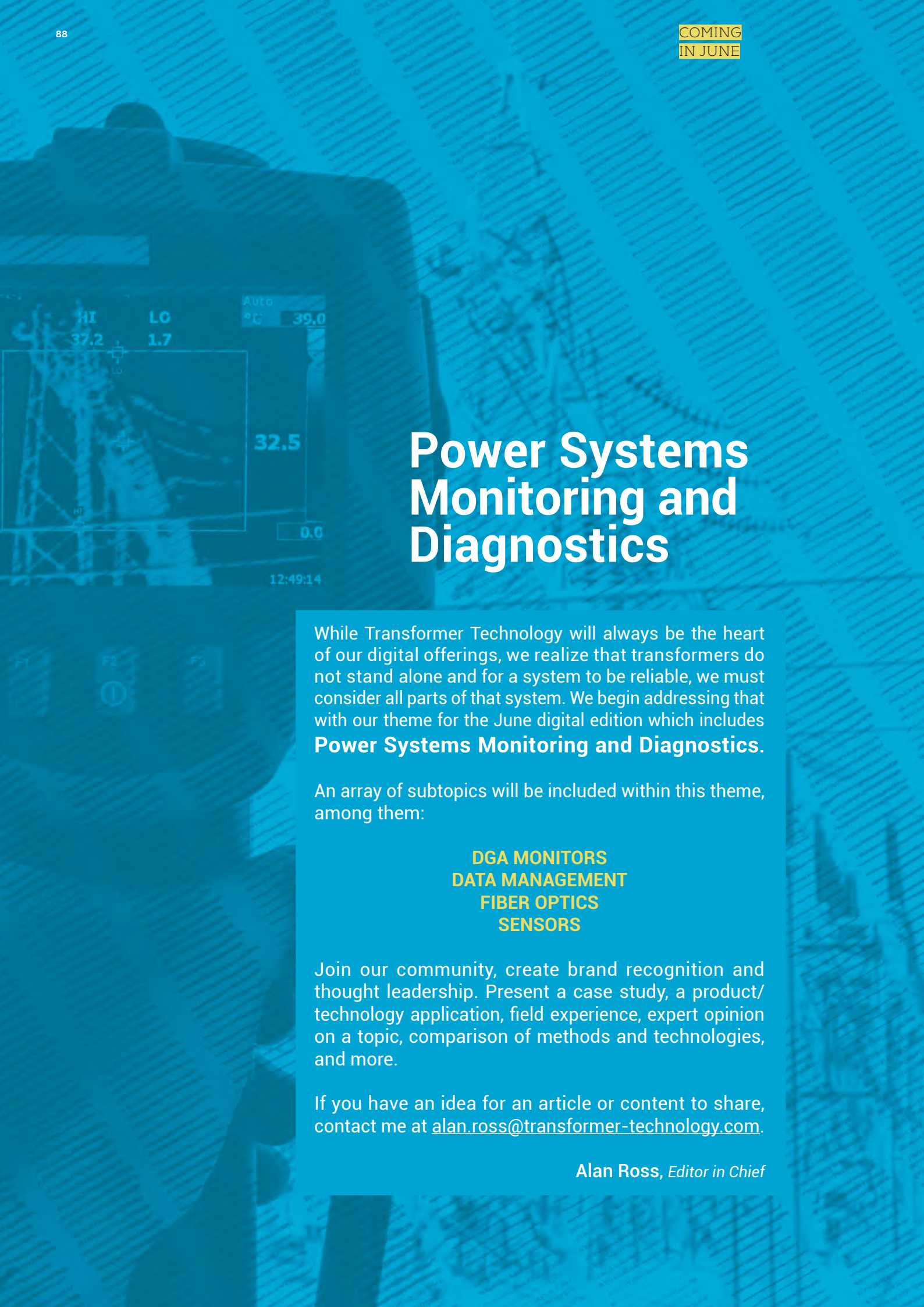


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Power Systems Monitoring and Diagnostics

While Transformer Technology will always be the heart of our digital offerings, we realize that transformers do not stand alone and for a system to be reliable, we must consider all parts of that system. We begin addressing that with our theme for the June digital edition which includes **Power Systems Monitoring and Diagnostics**.

An array of subtopics will be included within this theme, among them:

**DGA MONITORS
DATA MANAGEMENT
FIBER OPTICS
SENSORS**

Join our community, create brand recognition and thought leadership. Present a case study, a product/technology application, field experience, expert opinion on a topic, comparison of methods and technologies, and more.

If you have an idea for an article or content to share, contact me at alan.ross@transformer-technology.com.

Alan Ross, *Editor in Chief*