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CIGRE US National Committee
2013 Grid of the Future Symposium

Digital Protection – Past, Present, and Future

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SUMMARY

The first transmission line protective relay based on a digital computer was invented by G.D. Rockefeller and commissioned in 1971 at Pacific Gas & Electric Company. Although created as a technology demonstration, it performed its protection job perfectly. It showed to the electromechanically based industry a high speed protection system that could implement customized distance characteristics and decision logic, estimate fault location, and save oscillographic data. It took another 15 years for computing hardware technology and clever engineering to yield the first commercially successful transmission line relays based on microprocessors.

Digital relays also brought data communications which evolved in parallel with the protection functions. Early serial communications of valuable post-fault information has evolved to Ethernet networked integration of substation protection and control functions. Vendor-specific protocols evolved into the industry standards DNP3 and IEC 61850.

Meanwhile, the industry has moved towards monitoring of the grid over wide areas with synchrophasor measurements and data communications. The next phase of synchrophasor functional development will demonstrate closed-loop protection and control using data from a holistic, redundant, reliable synchrophasor data gathering system. New, conceptually simple wide area protection schemes will evolve to replace many functions in today's digital microprocessor relay boxes. Future digital relaying approach uses coming communications infrastructure for synchrophasors with simple, broad protection designs.

KEYWORDS

Digital protection	IEC 61850
Microprocessor relay	Synchrophasor measurements
Substation integration	WAMS and WAMPAC

INVENTION OF THE DIGITAL RELAY

George D. Rockefeller, then a protective relaying application expert at Westinghouse Electric Corporation in the 1960s, published in 1969 the landmark paper *Fault Protection with a Digital Computer* [1] based on his research that began in 1967. That paper, written in the era of large mainframe computers, described implementation of all of the protective relaying for a substation on a single computing platform. However, even during the publication time interval, new scaled-down and robust minicomputers were being introduced for industrial and power plant applications. Rockefeller thus began in late 1969 the development of a digital computer based relay for protection of a single transmission line.

In the same time frame, Dr. Ian Morrison of the University of New South Wales, Australia and his colleagues were pondering the design of transmission line protective relaying software for a digital computer based relay [3], and published algorithms for computing numerical voltage and current values from sequences of instantaneous signal sample values [2].

DEVELOPMENT & INSTALLATION OF THE WORLD'S FIRST DIGITAL RELAY

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G.D. Rockefeller and his team commissioned the world's first transmission line relay based on a digital computer at Tesla Substation of Pacific Gas & Electric Company (PG&E) near Tracy, CA in February 1971 [4]. The line relaying system, named Prodar 70, was developed on an industrial minicomputer of a type created for control of utility gas turbine generators. The experimental relaying system was connected by PG&E to protect the 230 kV Tesla-Bellota line, operating in parallel with the existing EM relays.

Figure 1 shows the Prodar 70 system during model power system testing. The closet-sized cabinet contained the minicomputer (A) with power supply, I/O, and A/D conversion subsystem. The user interface comprised a Teletype printer (C), paper tape reader (D) and punch (E). A 3 kVA inverter (L) powered the system from the station battery. The 16-bit computing platform had 128kB of magnetic core memory with a typical read/ write cycle time of 7 microseconds for one 16 bit data value. Accordingly, the key demand was to develop highly tuned logic and lookup table programming that could keep up with 12 three-phase V & I sample sets per power cycle.

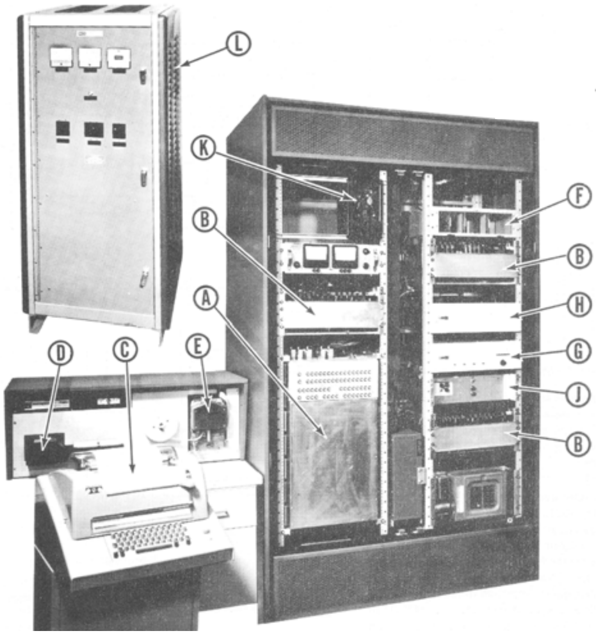

Figure 1 – Prodar 70 Digital Protection System

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1/ 5/71 PRODAR 70 LOGGING EVENTS AT 18 HR. 41 MIN. 46 SEC.
GROUND FAULT DETECTOR OPERATED; SKCNTR =  30955
FTA FOUND NO SEVERE CONDITIONS,
TIME =  18 MSEC.; SKCNTR = 30969
ZONE 2 GROUND DISTANCE OPERATION, PHASE B,
LAST APPARENT IMPEDANCE -  5.2 OHMS AT   77 DEGREES
TIME =  41 MSEC.; SKCNTR = 30992
ZONE 1 GROUND DISTANCE TRIP, PHASE B,
FAULT APPROX. 76.5 MILES FROM THIS POINT
LAST APPARENT IMPEDANCE -  4.9 OHMS AT   71 DEGREES
TIME =  43 MSEC.; SKCNTR = 30994
EXIT FROM RELAYING LOGIC,
TIME =  87 MSEC.; SKCNTR = 31038
EXTERNAL RELAY OPERATED,
TIME = 428 MSEC.; SKCNTR = 31379
GROUND FAULT DETECTOR OPERATED; SKCNTR =  31510
FTA FOUND LOW LINE-TO-GROUND VOLTAGE, PHASE C,
TIME =   6 MSEC.; SKCNTR = 31512
EXIT FROM RELAYING LOGIC,
TIME = 108 MSEC.; SKCNTR = 31614

RECORD    44 CURRENT MEDIANS:
RESERVED TABLE 1 @ 22B8            RESERVED TABLE 3 @ 23C2
IA -   4.22 AMPS.                  IA -   4.13 AMPS.
VA -  98.90 VOLTS                  VA -  98.55 VOLTS
IB -   4.13 AMPS.                  IB -  18.34 AMPS.
VB -  98.68 VOLTS                  VB -  89.84 VOLTS
IC -   4.34 AMPS.                  IC -  20.72 AMPS.
VC -  98.72 VOLTS                  VC -  84.17 VOLTS
IR -   0.16 AMPS.                  IR -   6.93 AMPS.
RESERVED TABLE 2 @ 233D            RESERVED TABLE 4 @ 2129
IA -   4.13 AMPS.                  IA -   4.28 AMPS.
VA -  97.84 VOLTS                  VA -  98.63 VOLTS
IB -  13.65 AMPS.                  IB -   4.13 AMPS.
VB -  95.75 VOLTS                  VB -  98.53 VOLTS
IC -  19.48 AMPS.                  IC -   4.31 AMPS.
VC -  94.31 VOLTS                  VC -  98.53 VOLTS
IR -   6.50 AMPS.                  IR -   0.19 AMPS.
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Figure 2 – Prodar 70 Event Log Example

Prodar 70 performed perfectly in six years of field service. Typical trip time was around 18 ms for faults out to about 60% of Zone 1, and 6 ms for a high-set overcurrent trip – all more than competitive with conventional relays next to which it served. It demonstrated perfect relaying behavior in field service, issuing a trip output for every internal fault, and never overtripping or false tripping. There was one incident after several years in which a technician inadvertently reversed the polarity of the ct inputs, after which Prodar 70 issued trip outputs for several reverse faults on other lines from the Tesla 230 kV bus – doing exactly what one would expect with the ct polarity reversed. There were no field hardware failures. Prodar 70 included a voltage memory polarizing function that enabled it to properly restrain for all faults on the adjacent series-compensated 500 kV lines, even with bus voltage reversal. Prodar 70 was removed from service in 1977 after it had provided all the experience that PG&E and the developers expected to get.

DEMONSTRATED BENEFITS OF DIGITAL RELAYING

Prodar 70 was not developed as a new product for sale – it was a technology experiment to discover the benefits and limitations of using a digital computer for protective relaying. The protection world saw for the first time many of the benefits we now take as core features of digital relaying technology – features never seen in any conventional relay of the day:

1. Event record displays - Prodar 70 used its Teletype printer to log an event report after each fault detector operation – Figure 2 shows an example from a lab test. Prodar 70 reported here

that it made an end-of- Zone 1ground distance trip decision in 43 ms. The faulted phase was reported. The "External Relay Operated" event refers to Prodar 70's report of the trip time of the conventional EM relaying system next to which it served in field service.

2. Fault location - PG&E noted the faulted phase identification and fault location estimate computed from the fault impedance. The accuracy of fault location in service was comparable to that of commercial microprocessor relays that came along 15 to 20 years later.
3. Analog value logs and oscillographic records – Figure 2 shows voltage and current magnitudes, computed from records of prefault, fault, and postfault voltage and current samples. The saved sampled data was automatically output via the paper tape punch for separate plotting of oscillographic traces.
4. Tailored reach characteristics with load restriction capability – Prodar 70 used a numerical impedance calculation process and distance reach boundaries optimized for the specific application, as shown in Figure 3.
5. Self -monitoring of protection system electronics –Prodar 70 combined a failure dead-man alarm, held open by active program stimulation, with a programmed routine that monitored the operation of the A/D converter subsystem.

SUBSEQUENT DIGITAL RELAY DEVELOPMENTS

Utility technology leaders and academic researchers now understood the unlimited possibilities for flexible design of new protection solutions with mathematically based characteristics and sophisticated, adaptive decision logic, plus data capture and reporting.

A team lead by Dr. A.G. Phadke, then at American Electric Power (AEP) in New York, had already been developing a digital relaying system in the early 1970s that demonstrated a unified symmetrical component computing algorithm that handled all types of faults [5]. It was during this work that team members first conceived of synchrophasor measurements.

As these trial digital relaying systems operated on minicomputer platforms in the 1970s, the first microprocessors appeared from Intel and Motorola. If minicomputers challenged programmers' real-time coding skills, these first microprocessors simply lacked adequate computing capability. However, their capabilities would advance at a rapid pace from that time.

It was at the start of the 1980s that Dr. E.O. Schweitzer conceived of mathematically efficient relaying element computations which could operate on an economical microprocessor platform with a sampling rate of 4 per power cycle and a measurement process derived from the Fourier transform [6]. Schweitzer and his team created low-cost practical protective relays whose protection performance was reliable and whose trip speeds were adequate for the majority of applications. Early commercial microprocessor relays from Schweitzer Engineering Laboratories (SEL) leveraged the already-demonstrated benefits of event records and oscillograms plus fault location capability with serial data communications that could be accessed on site or remotely with modems. Schweitzer is recognized as the pioneer in the successful commercialization of digital relaying technology, and the creator of a massive, vibrant, and respected relay manufacturing business internationally.

DIGITAL RELAYS TODAY

Digital relays have evolved to massive processing power. Vendors compete with sophisticated relaying elements and functions, along with growing arrays of new functions, all concentrated in single products also offering generous user programmable logic capability. Configuration of so much functionality is defined by dense listings of thousands of settings – users struggle to learn the configuration process and to manage the setting records with a minimum of errors in design, commissioning, and maintenance.

The electronic hardware from which modern relays are built is far more reliable than any prior generation, even considering the complexity. On top of this benefit, these relays have expanded the self monitoring capability first demonstrated in Prodar 70 to cover all the mission-critical hardware in the product except the normally-static inputs and outputs. The relay alarms for failures, improving protection reliability and eliminating most periodic testing.

Digital relays are supplied on platforms built of mass-market computing technology having shorter technical life with each new generation. This rapid obsolescence is driven by the suppliers of electronic hardware for broader electronic industries. Users must now grasp the reality of rapid product generation change by designing panels and installations for efficient and rapid replacement of entire zone protection and control packages while keeping the panels and buildings in place. Capital programs must also support frequent replacements. The designs must allow such replacement without outages on stressed grids. See [10] for detailed situational assessment and advice.

Users who would shun the complexity and frequent replacement regimen of today's digital relays should contemplate the economic drivers that brought us to the present state. A telling observation is that the price of a sophisticated modern microprocessor transmission line relay today is *between 2% and 4% of the price* of a 1970-era electromechanical panel with far less protection functionality (constant-dollar comparison). There is no prospect for moving backwards.

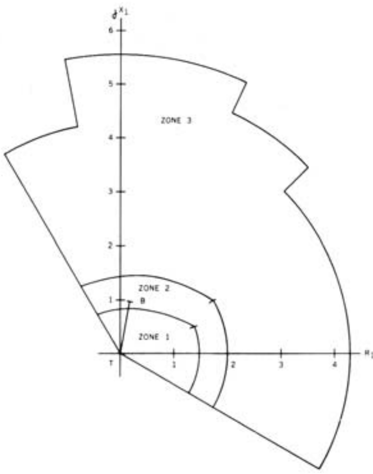

Figure 3 – Prodar 70 Zone Reach

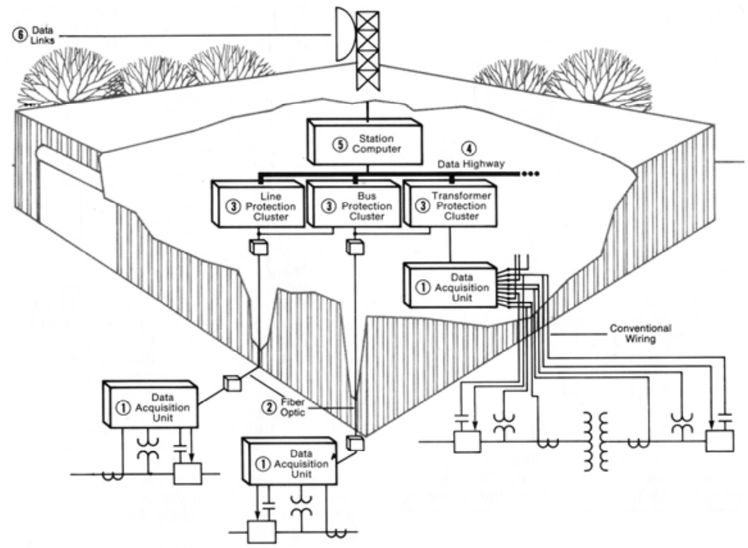

Figure 4 – Integrated P&C System Overview

INTEGRATING PROTECTION & CONTROL WITH DATA COMMUNICATIONS

The critically useful information a digital relay could capture made data communications a focus of industry interest in the 1970s. Enterprise computer networking first penetrated office environments, while more robust serial networking integrated programmable logic controllers in industrial applications. Forward-looking protection and control (P&C) engineers contemplated the tying together of microprocessor relays, along with programming of integrated substation control logic, and even the raw sources of process information from the switchyard using multiplexed data communications networks in place of point-to-point wiring.

Between 1978 and 1986, the Electric Power Research Institute (EPRI) sponsored development of a fully integrated substation P&C system called WESPAC [7], based on protection zone processors with control logic for lines, buses, and transformers as shown in Figure 3. Zone relaying processor clusters exchanged critical P&C information over a multidrop optical fiber data communications network. A substation computer integrated the functions of all the zones, gathered operational and fault data, and communicated directly with the utility control center via a supervisory control and data acquisition (SCADA) protocol in place of a separate remote terminal unit (RTU). The line relaying processor featured an added optical fiber multiplexed data connection to an environmentally protected data acquisition and control unit (DAU) which connected to instrument transformers and circuit breakers in the switchyard. The DAU is the functional equivalent of what is now called a merging unit (MU) in IEC 61850 [8] . A major goal was to eliminate most of point to point wiring – even for critical ac sample value transmission and high-speed relaying trip or control signals.

The comprehensive integrated substation P&C technology demonstration was commissioned at Deans 500 kV substation of Public Service Electric & Gas Company (PSE&G) of New Jersey in 1986. The EPRI system emphasized completeness of the demonstration over commercial development focus, but drew industry attention to the concept of integrated protection and control.

Meanwhile, the commercial P&C marketplace continued its focus on individual zone microprocessor relays with more basic serial data communications. SCADA RTU makers and others began development of substation communications processors to interface the relays as data and control severs for SCADA, circumventing some of the RTU point connections, and bringing the operational data from the relay to the control center or to other users like protection engineers. Unfortunately, the energy of this integration effort was dissipated by the challenge of integrating all the different communications protocols – each product vendor had its own. One technically solid offering from the RTU maker Westronics (now General Electric) was the protocol DNP3, which gained footing with an increasing array of vendors and became the *de facto* North American standard for integrating SCADA and operator control communications with user point mapping for connection of functions.

ROLE OF IEC 61850

In the 1990s, North America and Europe were each struggling with the promise of communications-based integration for substations, versus the challenge of incompatible vendor specific protocols. In North America, EPRI launched the Utility Communications Architecture (UCA) project to roadmap the integration of the entire utility enterprise, and identify the communications protocols and methods for each subpart. In substations, the UCA work looked not only at the communications protocol or the means of connecting data signals, but also at standardizing the data-map interfaces of entire *functions*, to support an automated process for configuring an installation. Meanwhile, European and North American participants initiated the standard project IEC 61850, *Communication networks and systems in substations* (the original name, reflecting the limited early scope) in 1995-96, with the goal of creating a single international standard communications protocol and functional integration modeling scheme that all vendors and users would embrace to create interoperable multivendor installations. In 2000, the UCA and IEC 61850 projects merged to achieve the single international solution that all the participants sought.

See IEC 61850-1 [9] for an overview of the design concepts. Many papers have been written on the concepts, goals and benefits – see PACworld magazine at http://www.pacw.org/ for articles, links, and rich background on application and experiences. Today, editions or versions of the many IEC 61850 standard parts carry the more ambitious title *Communication networks and systems for power utility automation*. There will be a continuous evolution and growth of such a broad standard – there is no development end point.

In North America, IEC 61850 application has been challenged and slowed by utility preference for user-integrated multivendor designs, as opposed to turnkey installations from one vendor often used elsewhere in the world. Users have had problems with integration of multiple vendors' products that aim to conform to such a complex functional standard, but fail in the interpretation of the details. Integration tools for configuring multiple vendors' product functions have been notably troublesome. New interoperability testing will expose issues and improve products.

Notwithstanding the ongoing work to improve the application experience, there is no alternative to moving forward with refinement and application of IEC 61850. In the face of increasing product complexity, and constantly-shortening technical life of new P&C products, hand-configured P&C installations become unsustainable. Standing still is not an alternative.

SYNCHROPHASOR APPLICATION AND RELAYING DEVELOPMENT

The author and colleague have presented in [10] a roadmap for industry deployment of protection and control functions using synchrophasors, advancing beyond today's focus on situational awareness displays to operators (wide area monitoring systems or WAMS), and beyond validation of power system models. Trustworthy models enable the simulation, and deployment of wide area control schemes that analyze and stabilize system state changes in time frames of milliseconds, beyond the capabilities of human operators. The industry thus turns its research focus on wide area monitoring, protection, automation, and control (WAMPAC) systems.

Protective relaying, in particular, can be carried out in uniform schemes that build out from local primary protection zones in backup zone layers using the synchrophasor measurements gathered from across the network. The author recently presented [11] a high level concept for layered application of backup fault protection using Kirchoff's current law with wide area synchrophasor current measurements. Voltage synchrophasor measurements using the same data collection scheme can provide predictive out-of-step protection for load swings and stability problems to which the current differential fault protection concept is blessedly blind.

CONCLUSION - THE FUTURE OF DIGITAL PROTECTION & CONTROL

Today, large utilities are investing millions of dollars in wide area coordination studies in which precise system and protective relay models simulate every conceivable fault and stress condition response to find the best compromise of remote backup distance relay functions and settings. For some stressed grids with diverse and unpredictable generation sources, the resulting brittle solution is valid for one particular operating state – even line or equipment maintenance invalidates some settings and leaves the owner vulnerable to relay misoperations. The large investment and staff focus on coordination begs for a completely new solution that is inherently invulnerable to the influences that require all the coordination checking work and expense.

The author sees the combination of local primary protection and essentially setting-free wide area backup protection built on synchrophasor current and voltage comparison principles, characterized in [11], as the future of digital protection.

Complexity doesn't go away with this new approach – it moves into new domains that are better aligned with the skills of the future generation of P&C engineers:

- This scheme requires highly available, mission critical, n-redundant, self monitoring, and cyber-secure data communications networks across the wide area of the grid. Our industry has already begun and will be busy creating this infrastructure for years to come, based on examples and positive experiences from outside the utility industry.
- The scheme must precisely associate data point configurations holistically across the grid. The configuration mapping database must be managed and protected.

Once the enterprise creates this underlying layer of wide area synchrophasor data collection and sharing, it serves all enterprise functions using system measurements. Even a sophisticated centralized energy management system (EMS) can operate exactly as it does today, with only the underlying data collection infrastructure of RTUs replaced by the synchrophasor data gathering system. It will then be able to migrate, under control of EMS managers, to improved performance and new functions using the rich wideband stream of synchrophasor data from the new collection platform serving all users.

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