PROTECTION & CONTROL ENGINEERING

Where the Study, the Design and the Compliance Obligation Meet

Protection scheme design, relay settings and coordination, IEC 61850 station architecture, SCADA integration and the PRC evidence that follows — at distribution, transmission and generator terminals, from 4 kV to 765 kV.

A setting sheet is the one document where a bus configuration, a fault study, an equipment rating and a reliability standard all have to agree at once.

That is why protection is where inconsistency surfaces. The coordination study assumed a fault duty the short circuit model no longer produces; the relay was replaced but the scheme was never re-verified; the setting in the relay does not match the setting in the compliance evidence. We design the scheme, model the relays, produce and coordinate the settings, and support the testing that proves them — with the short circuit and coordination work that underpins all of it done by the same firm.

30+	4–765 kV	7	4
YEARS ACROSS TRANSMISSION, GENERATION & SUBSTATIONS	PROTECTION DESIGN AND SETTINGS RANGE	EHV BULK SUPPLY POINTS — MULTI-YEAR PROTECTION & CONTROL PROGRAM	U.S. OFFICES — TAMPA, AUSTIN, SACRAMENTO, BALTIMORE

SCOPE | Scheme design | Relay settings | Coordination | IEC 61850 | SCADA | RAS & load shedding | PRC evidence

WHERE WE WORK

01 Philosophy
Protection philosophy, redundancy and scheme selection against the owner's standard.

02 Design
One-lines, three-lines, AC and DC schematics, panel design, wiring and connection diagrams.

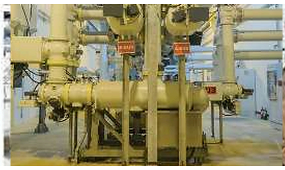
03 Settings
Short circuit, coordination, setting sheets, relay files and coordination curves.

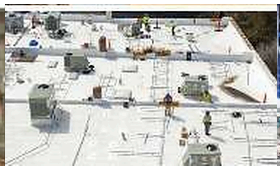
04 Integration
IEC 61850 station architecture, SCD engineering, SCADA point lists and telemetry.

05 Commissioning
Test plans, witnessing, troubleshooting attendance and as-left review.

06 Compliance
PRC evidence, maintenance program design, misoperation analysis and mitigation.








START A SCOPE ›› Send the one-line, the relay list and the driver — a replacement, a new terminal, a coordination problem or an audit finding — and we will come back with a scoped fee and what data we need.

NSPE | D·U·N·S REGISTERED | IEEE SENIOR MEMBER | BBB ACCREDITED A+

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THE DESIGN BASIS

Protection Scheme Design

Every element below is designed against a current IEEE guide — and several of the editions most often cited in this industry are no longer the current ones.

WHAT WE PROTECT	GOVERNING GUIDE	THE ENGINEERING
Transmission lines	IEEE C37.113	Distance zone design and reach, directional comparison, permissive and blocking pilot schemes, weak infeed and echo logic, single-pole tripping and reclosing philosophy, loadability against PRC-023
Line current differential	IEEE C37.243	Channel arrangement and asymmetry, alignment method, in-zone transformer treatment, charging current compensation, and the backup scheme behind the differential
Power transformers	IEEE C37.91-2021	Percentage differential with inrush and overexcitation restraint, restricted earth fault, thermal and overload protection, tap changer and cooling alarms, through-fault duty
Buses	IEEE C37.234-2021	High-impedance and low-impedance busbar differential, CT selection and saturation analysis, dynamic bus replica logic, and check-zone arrangement
Generators	IEEE C37.102-2023	Internal fault, system fault and abnormal operating condition protection — differential, ground fault, loss of field, negative sequence, reverse power, over-excitation, frequency and voltage protection coordinated with PRC-024 and PRC-025
Breaker failure	IEEE C37.119-2025	Initiation logic, current supervision, timer coordination against the interrupting scheme, retrip and adjacent-zone clearing — retitled and revised in 2025
Distribution feeders	IEEE C37.230-2020	Overcurrent and ground coordination, reclosing and sectionalising, cold load pickup, fuse saving versus fuse blowing, and DER-aware settings
Motors	IEEE C37.96 / 3004.8	Thermal model and overload, locked rotor and starting, unbalance and single phasing, differential on large machines

The Buff Book is no longer a live standard

IEEE Std 242 — the Buff Book — was inactivated in 2021, and its content has migrated into the IEEE 3004 series: 3004.5 for low-voltage circuit breaker application, 3004.7 for conductor protection, 3004.8 for motor protection and 3004.11 for bus and switchgear protection. A great deal of consulting material still cites the Buff Book as current. We cite the standard that is actually in force, and we name the edition in the deliverable.

Redundancy philosophy

Primary and secondary protection selection, dual DC supplies, separate trip coils and independent measurement paths — decided against the owner's standard and the consequence of a failure to operate, not by habit.

Instrument transformers

Ratio, accuracy class, burden and saturation behaviour under the worst-case fault. A differential scheme designed on a CT that saturates is a scheme that misoperates on through faults.

DC systems

Battery duty cycle, charger sizing, DC short circuit and voltage drop to the trip coil — the part of a protection system that is invisible until the day it does not operate.

Design against the owner's standard, or write one

Most utilities have a protection philosophy document; most industrial owners, renewable developers and data center operators do not, and inherit whatever each project's EPC preferred. Where one exists we design to it and flag where it conflicts with current guidance. Where none exists we will write it — a short document setting redundancy, scheme selection, setting conventions and naming, so that the fifth substation looks like the first.

THE CORE DELIVERABLE

Settings and Coordination

No standard prescribes what a settings package must contain. This is what ours contains, and why each part is in it.

What you receive

- **The model basis** — short circuit and load flow cases, with the source impedance, configuration and contingency assumptions stated
- **Instrument transformer review** — ratio, accuracy class, burden and a saturation check, because a differential scheme is only as good as the CT behind it
- **Per-element setting sheets** with the calculation basis for every value, not just the value
- **Time-current coordination curves** showing the intervals actually achieved and any compromises made deliberately
- **Relay-specific setting files** in the manufacturer's native format, ready to load
- **Logic and scheme drawings** where the setting alone does not describe the behaviour
- **A test plan** written so the testing contractor can prove the scheme, not just the elements
- **An as-left verification summary** for the record and the compliance evidence

Where coordination genuinely cannot be achieved

Sometimes selectivity and equipment protection are in direct conflict and no setting satisfies both. We say so in the deliverable, show the exposure, and give the options — a scheme change, a device change, or an accepted and documented compromise. An exception written down is an engineering decision. An exception left out is a finding waiting to happen.

THE WORK THAT MOST OFTEN NEEDS DOING

Digital relay replacement

Replacing an electromechanical or early microprocessor relay is rarely like-for-like. The characteristic changes, the logic that lived in auxiliary relays and wiring migrates into the relay, and the scheme has to be re-proved.

Settings translation from electromechanical characteristics to numeric equivalents — not a transcription, a re-derivation against the current fault study

Scheme re-verification where hardwired logic becomes programmable logic, including trip and close paths, lockout and permissives

Communications and integration — what the new relay now reports, and what the SCADA system expects

Arc flash and coordination re-study, because a new device with instantaneous capability changes both

Records, because the audit asks

- No US standard mandates a particular settings-management system — but PRC-004 requires misoperation cause evidence and PRC-005 requires demonstrable maintenance records
- Which makes records discipline an effective audit requirement even though the tooling is not prescribed
- We deliver a settings register with revision history, the basis for each change, and the as-left record — in a form that drops into your evidence package rather than needing reconstruction

Settings against a current model, not a legacy one. The most common finding in a settings audit is a value derived from a fault study that predates two system changes

Coordination intervals shown, not asserted. The curves state what was actually achieved, including where the margin is thinner than the guideline

Native files, not just sheets. The setting file loads directly into the relay, which removes an entire class of transcription error at commissioning

The calculation basis travels with the value. A reviewer, an auditor or your own engineer in three years can check the setting without reconstructing the study

Coordination is a system property, not a device property

A setting that coordinates against the device below it and fails against the device above it has not been coordinated — it has been set. The study has to run the full path from the source to the last protective device, at maximum and minimum fault levels, across the switching configurations the system actually operates in. That is more cases than most coordination studies contain, and it is where the uncoordinated pairs hide.

THE COMPLIANCE LAYER

The PRC Standards, and the Engineering Behind Them

Most PRC findings are not filing failures. They are a setting that does not match the study, a rating with no calculation behind it, or a maintenance interval nobody can demonstrate was met.

STANDARD	SUBJECT	THE ENGINEERING EVIDENCE IT ACTUALLY NEEDS
PRC-002	Disturbance monitoring	Sequence of events, fault recording and dynamic disturbance recording — specification, coverage determination and data retrieval
PRC-004-6	Misoperation identification	Cause analysis within 120 days, co-owner notification, a corrective action plan within 60 days of cause identification, and at least 12 months of evidence retention
PRC-005-6	Protection system maintenance	Program design by component type, interval basis, performance-based justification where used, and the as-found and as-left records that prove it
PRC-006	Automatic underfrequency load shedding	Scheme design, allocation, relay settings and the modeling that supports the regional program — increasingly complicated by distributed resources on the shed feeders
PRC-012-2 / PRC-017	Remedial action schemes	Attachment 1 documentation to the Reliability Coordinator, five-year Planning Coordinator evaluation, 120 days to analyse an operation or failure to operate, and maintenance and testing to PRC-017
PRC-019	Generator voltage control coordination	Coordination of voltage regulator limiters, protection and equipment capability — a study, not a form
PRC-023	Transmission relay loadability	Loadability calculation for every applicable circuit, with the criterion applied and the exceptions justified
PRC-024-4	Frequency & voltage protection settings	Generator and IBR protection settings inside the no-trip envelope — **effective 1 October 2026**
PRC-025	Generator relay loadability	Setting the load-responsive elements on generators, transformers and unit auxiliaries to the applicable option
PRC-026	Stable power swing performance	Criterion screening and the swing study behind any element that fails it
PRC-027	Protection system coordination	The coordination process and the studies that demonstrate it across ownership boundaries
PRC-028-1	IBR disturbance monitoring	Sequence of events and fault recording with defined sampling and duration, continuous recording, UTC synchronisation, and delivery in COMTRADE and CSV within 30 days — **effective since 1 April 2025**, phasing to full coverage
PRC-029-1	IBR ride-through	Ride-through per the attachment, reactive support and current prioritisation, real power restoration within one second of voltage recovery — **effective 1 October 2026**
PRC-030-1	Unexpected IBR events	Event identification, analysis, corrective action plan or technical justification, and mitigation — **effective 1 October 2026**

SCOPE NOTE We produce the technical evidence. NERC CIP cyber security is a separate discipline, coordinated with your own cyber security team rather than performed by us.

THE DATE ON EVERYONE'S CALENDAR

1 October 2026

Three standards take effect on the same day, all of them landing on inverter-based resource protection settings — and NERC has publicly warned that the people who change those settings are not available.

PRC-024-4

Frequency and voltage protection settings for generators and inverter-based resources. The no-trip envelope your protection has to sit inside.

PRC-029-1

Ride-through for IBRs, reaching non-BES resources of 20 MVA or more in aggregate at 60 kV and above. Hardware-limitation exemptions must be requested within twelve months of the effective date.

PRC-030-1

Unexpected IBR event mitigation — identify, analyse, correct or justify, and mitigate. Non-BES resources comply by the later of 1 January 2027 or the effective date.

NERC SAID THIS OUT LOUD, IN A COMPLIANCE BULLETIN

The people who change the settings are booked

NERC's July 2026 compliance bulletin warned that Generator Owners are encountering limited availability of qualified inverter OEMs and contractors needed to support the required equipment setting modifications ahead of the October deadline. That is a documented capacity gap, published by the regulator, one quarter before the date.

What we can do — the engineering that has to precede any setting change: determine applicability, establish the required envelope, identify every element currently set inside it, and produce the specific change list the OEM has to implement

What we cannot do — touch the inverter firmware. That belongs to the OEM. But the queue for the OEM is shorter when they receive a finished, verified change list instead of a request to investigate

A caution about the older PRC standards

NERC's own compliance dates document flags PRC-002, PRC-004, PRC-005, PRC-019, PRC-023, PRC-024, PRC-025, PRC-026 and PRC-027 as requiring modification for inverter-based resource applicability, with no compliance date yet set. If you own IBRs, expect this set to move — and design your programme so a change of applicability is an update rather than a rebuild.

Applicability first

PRC-029 reaches BES inverter-based resources and non-BES resources of 20 MVA or more in aggregate at 60 kV and above. Establishing which of your plants are captured, and from what date, is the first hour of work — and it is not always the answer people expect.

Then the gap list

Every protective element currently set inside the required envelope, identified by plant, by unit and by function, with the required value beside the present one. That document is what makes an OEM engagement short.

Then the evidence

The as-left record, the technical basis, and where a hardware limitation genuinely prevents compliance, the exemption request with the engineering behind it rather than an assertion.

Start now, not in September. The engineering that must precede a setting change takes weeks; the OEM queue for implementing it is the part NERC has warned about

Non-BES resources are captured too. A 20 MVA aggregate threshold at 60 kV reaches plants many owners assume are outside the reliability standards entirely

The awkward question worth asking your OEM now

Can the inverter actually meet the required envelope, or is there a hardware limitation? The exemption route exists precisely because for some installed fleets the answer is no — but a request has to be made within twelve months of the effective date and has to carry an engineering basis, not an assertion. Finding out in 2027 that a fleet cannot comply and the exemption window has closed is a materially worse position than finding out now.

THE DOMINANT DRIVER

Inverter Protection Is Tripping Plants Offline

Four disturbances in one region in four months, each losing hundreds of megawatts to protection that operated as configured — and mostly should not have.

DISTURBANCE	LOST	WHAT HAPPENED
Vincent 500 kV 25 March 2024	1,046 MW	Phase-to-ground fault during breaker restoration. 28 solar PV and wind units tripped.
Hickory–Red Butte 345 kV 12 May 2024	532 MW	Phase-to-phase fault. 8 solar PV units tripped.
Windhub 500/230 kV 20 May 2024	698 MW	Differential protection operation on a separated riser lead. 22 solar, wind and BESS units tripped.
Midway–Vincent 500 kV 15 June 2024	934 MW	Fire-induced line trip. 37 solar, wind and BESS units tripped.

Trip mechanisms identified across the four events: DC overvoltage, over- and underfrequency, AC overcurrent, module faults and unbalanced voltage. All four are Western Interconnection events documented in NERC's disturbance report.

What NERC found when it looked at the settings

- **Phase-locked loop loss-of-synchronism protection** "has resulted in many inverters tripping during past disturbances," with a recommended minimum 30-degree angle threshold
- Approximately **2,260 MW** found with protections set *inside* the PRC-024 no-trip zones — that is, configured to trip where the standard requires them to stay on
- **37% and 38%** of high- and low-frequency protection settings respectively using instantaneous, unfiltered measurement quantities
- NERC's 2026 State of Reliability records **16 events since 2020** with unexpected IBR output reduction exceeding 500 MW, and a 2025 event losing **1,132 MW** to sub-synchronous oscillation protection — a failure mode it describes as previously unobserved at that scale

THE RECOMMENDATION NOBODY EXPECTS

Firmware updates can revert your settings

NERC's own recommendation is explicit: ensure that firmware updates do not revert previously optimised protective settings without owner approval. A plant that was compliant in March can be non-compliant in April because a maintenance update restored factory defaults, and nobody looked.

> We build the **as-left settings baseline** that makes this detectable — a documented record of what every protective element was set to, against which a post-update audit is a comparison rather than an investigation

Why plant owners keep being surprised by this

Inverter protection settings are usually configured by the OEM at commissioning, held in firmware, and not visible in the documents the plant owner holds. The owner carries the compliance obligation for settings they did not choose, cannot see, and in many cases cannot change without a vendor visit. The first useful step is almost always the same: establish what the settings actually are today, plant by plant, and write them down.

What we produce — the as-found settings baseline across a fleet, the gap list against the required envelope, and the specific change list the OEM implements

What it prevents — a plant that was compliant at commissioning and is not today, because nobody compared the settings after a maintenance update

NOTE Low fault current from inverter-based sources also complicates conventional overcurrent and distance coordination. We treat that qualitatively — the physics is real, but we do not print figures NERC has not published.

DIGITAL SUBSTATION

IEC 61850, Honestly

Station bus is mainstream. Process bus is not. A vendor who tells you otherwise is selling you a project that your maintenance organisation cannot yet support.

What we engineer

- **Station architecture** — network topology, redundancy (PRP and HSR where used), time synchronisation and the segregation of protection from station traffic
- **GOOSE scheme design** — interlocking, breaker failure initiation, transfer trip and blocking, with the performance class and supervision that make it dependable
- **SCL engineering** — system specification, IED capability and instantiated descriptions, and the substation configuration description that ties them together
- **Data modelling** — logical nodes, datasets, report control blocks and the point list your SCADA and historian actually consume
- **Process bus where it is justified** — merging units and sampled values, with an honest assessment of the testing and maintenance consequences before it is committed
- **Conformance and integration testing** plans, and the factory and site test scope behind them

Conformance is not interoperability

Conformance certification proves that a device implements the protocol correctly. It does not prove that your particular set of devices, from different vendors, in your particular scheme, will work together. That still requires project-specific SCD engineering and integration testing — and it is where digital substation projects overrun.

Two things worth getting right in writing

- **The edition.** IEC publishes 61850 as consolidated versions with amendments — the SCL part carries amendments through 2024 and the conformance testing part through 2025. There is no published "Edition 2.1," despite it being common industry shorthand. We cite it as Edition 2 with current amendments, because that is what the catalogue says.
- **The SCD is a deliverable, not an artefact.** It is the single file that describes your station, and it has to be owned, versioned and maintained after the integrator leaves. We hand it over documented, and we say who should own it.

THE BARRIER IS NOT THE TECHNOLOGY

Testing and maintenance practice

EPRI's digital substation work identifies knowledge preparation and the difficulty of developing new approaches to protection system testing and maintenance in a digital environment as principal barriers. That matches what we see: the design is achievable, and the question that stalls projects is who tests it in year three, with what equipment, and against what procedure.

> We will not publish an adoption percentage for process bus in North America, because no primary source publishes one. What we will do is tell you honestly what your own organisation is set up to maintain.

Network topology and redundancy design	GOOSE scheme design and supervision	SCL and SCD engineering
Logical node and dataset modelling	Time synchronisation architecture	Point lists and SCADA mapping
Factory and site integration test scope	Handover documentation and ownership	Legacy protocol coexistence

When we recommend against it

Process bus is the right answer on some projects and a liability on others. If your organisation does not yet have the test equipment, the procedures and the trained people to maintain sampled-value protection in year three, we will say so — and design a station bus scheme that gets most of the benefit with none of that exposure. A digital substation nobody can test is not a modernisation.

Retrofit into an existing station — legacy protocol coexistence, phased cutover and the interlocks that must keep working through both

New build — specified from the start, with the SCD and the test scope written into the procurement rather than negotiated afterward

BEYOND THE TERMINAL

Special Schemes, Load Shedding and Wide-Area Measurement

The schemes that act on the system rather than the element — and that carry the heaviest documentation obligations of anything in protection.

Remedial action schemes

- NERC standardised on **Remedial Action Scheme**; the older Special Protection System term persists regionally but has been consolidated
- **PRC-012-2** governs the lifecycle: Attachment 1 documentation to the Reliability Coordinator before in-service, functional modification or retirement; a four-month RC review; and a Planning Coordinator evaluation at least every five years including inadvertent-operation performance
- **120 days** to analyse a RAS operation or failure to operate, and **six months** to develop a corrective action plan
- **PRC-017-1** covers RAS maintenance and testing
- Both carry a **15 May 2026** Category 2 inverter-based resource compliance date
- What we produce: the scheme design and logic, the arming and operating criteria, the studies that justify them, the Attachment 1 package, and the test procedure

The documentation is the hard part

A RAS is usually straightforward to design and difficult to keep documented through five years of system change. The evaluations, the modification notifications and the operation analyses are where entities lose the thread — and we build the record so the next evaluation is a review rather than an archaeology exercise.

Load shedding

- **PRC-006** governs automatic underfrequency load shedding — scheme design, allocation across the region, relay settings and the supporting studies
- Undervoltage load shedding where the regional program requires it
- **PRC-005** reaches distributed UFLS and UVLS equipment for maintenance
- NERC's system planning work has published guidance on UFLS program design under increasing distributed energy resource penetration — because the load being shed is no longer the load the program assumed. A feeder with significant behind-the-meter generation sheds less real power than its nameplate suggests, and the program's effectiveness degrades quietly

Synchrophasors

- The current synchrophasor measurement standard is **IEC/IEEE 60255-118-1**, which superseded IEEE C37.118.1. Citing C37.118.1 as current is a common and easily checked error — we do not make it
- PMU placement and specification, data concentration architecture, and the analytics path from measurement to actionable event analysis
- Event and disturbance analysis using recorded data — often the fastest route to understanding a misoperation, and the evidence PRC-004 will ask for

These schemes fail quietly

A line protection failure announces itself. A remedial action scheme that has drifted out of step with the system it protects, or an underfrequency program shedding less real power than its allocation assumes, does not — until the day it is called on. That is why the periodic evaluation obligations in these standards exist, and why they are the ones most often treated as paperwork rather than as engineering.

RAS logic and arming criteria	Attachment 1 documentation package	Five-year evaluation support
UFLS allocation and settings	UVLS scheme design	PMU placement and specification

The scheme nobody re-checks

Breaker failure protection is initiated by every other scheme in the station and coordinates against the interrupting time of a breaker that may since have been replaced. Its timer is one of the most consequential settings in a substation and one of the least often revisited — and IEEE C37.119 was revised and retitled in 2025, which is a reasonable prompt to look at yours.

COMMISSIONING & FIELD SUPPORT

Where Our Work Ends, Stated Plainly

We write the test plan, attend the test and review the results. We do not self-perform relay testing — and we would rather say that here than at the kickoff meeting.

What we do

- **The test plan** — element tests, functional scheme tests and the end-to-end cases, written so the scheme is proved rather than the relay
- **Commissioning support and witnessing** — attendance at factory and site testing, with an engineer who can answer why a setting is what it is
- **Troubleshooting attendance** when a scheme does not behave as designed and somebody needs to decide whether it is the setting, the logic, the wiring or the model
- **As-left review** against the design intent, and the record that becomes your compliance evidence
- **Post-event analysis** using relay records, sequence of events and disturbance data

What the testing contractor does

- Field execution, test equipment and calibration traceability
- The field test reports and their accreditation
- Physical isolation, safety and the switching that goes with it

This split is a commercial convention, not a standard. We present it as how we work, and we are comfortable working the other way round — as the engineering support to a testing contractor who holds the field scope.

The documents that govern testing

- **IEEE C37.233-2023**, Guide for Power System Protection Testing — current; the 2009 edition is inactive-reserved
- **ANSI/NETA ATS-2025** for acceptance testing, which added dedicated battery energy storage and solar PV sections and medium-voltage cable acceptance values in the 2025 revision
- **ANSI/NETA MTS-2023** for maintenance testing
- **PRC-005** for the maintenance program the testing has to satisfy

THE TEST THAT FINDS THE REAL PROBLEMS

End-to-end, both terminals, one fault case

Synchronised test sets at both line terminals replaying a common fault case prove the whole pilot scheme — relays, logic, communications channel and timing — in a way that element testing at either end never can. It is the single highest-value test on a line protection commissioning, and it is the one most often skipped for schedule.

> We write it into the plan, and we say what the exposure is if it is dropped

> **Element testing** proves the relay measures and operates correctly. **Functional testing** proves the scheme does what the design intended. Passing the first and skipping the second is how a correctly set relay ends up in a scheme that does not trip

> **The as-left record closes the loop.** A setting designed, a setting loaded and a setting recorded should be the same number — and the only way to know is to compare them deliberately, which is a five-minute task nobody is assigned

We will work either way round

Some clients want a single firm holding engineering and field execution through a testing partner. Others already have a testing contractor they trust and want engineering support behind them. Both work. What does not work is a scope where each party assumed the other owned the functional test — which is why the split is written into the scope of work rather than left to convention.

- Element and functional test procedures
- End-to-end test cases
- Factory acceptance test scope
- Commissioning sequence and switching
- As-left review and record
- Event and disturbance analysis

WHY PROTECTION WORK EXISTS

Misoperations, and What Actually Causes Them

The causes are not exotic. They are settings, records and human performance — which is to say, they are addressable by engineering discipline.

RELIABILITYFIRST REGION, 2020–2024

133 misoperations in 2024, down from 277 in 2016

ReliabilityFirst's 2025 misoperation assessment attributes causes as equipment failures 44%, human performance 39%, and unknown or other 17% — with incorrect settings and as-left personnel error consistently among the top causes, and relay failures the largest single cause category.

> These are **ReliabilityFirst region figures**, not continent-wide. NERC's 2026 State of Reliability classifies the misoperation rate as stable with continued improvement, but publishes no numeric rate — so we do not quote one

Two of the top three causes are ours to fix

Incorrect settings and as-left personnel error are engineering and process failures, not equipment failures. They are addressed by deriving settings against a current model rather than a legacy one, writing the calculation basis down so a reviewer can check it, and closing the loop between the designed setting and the as-left record.

What we do after a misoperation

- **Retrieve and read the evidence** — relay records, oscillography, sequence of events and disturbance data, before anyone rewrites the history
- **Reconstruct the event** in the short circuit model and confirm what the elements actually saw
- **Identify the cause** against the PRC-004 categories, within the 120-day window
- **Produce the corrective action** — a setting change, a scheme change, a maintenance change or a model correction, with the technical basis behind it
- **Close it in the record** so the evidence package stands on its own at audit

And before one happens

- **Settings audit against the current model** — the most common finding is a setting derived from a fault study that predates two system changes
- **As-found versus design comparison** across a fleet, which is how reverted or undocumented settings are discovered
- **Coordination review after any source impedance change** — new generation, a new line, a transformer replacement or a network upgrade all move the answer
- **Maintenance program review** against PRC-005 intervals and what is actually being recorded

After a system change

New generation, a new line, a transformer replacement or a network upgrade all move source impedance. Every one of them is a reason to re-check coordination, and most of them do not trigger a review anywhere in the process.

After a relay change

A replacement device with instantaneous capability the old one did not have changes both coordination and incident energy — usually in opposite directions.

After a firmware update

NERC's own recommendation is to ensure updates do not revert optimised protective settings without owner approval. Without an as-left baseline there is nothing to compare against.

> **A settings audit is the cheapest engagement we offer** and the one that most often finds something — because it compares three things that should agree and frequently do not: the study, the setting file, and the record

> **Fleet-wide is cheaper per site than site-by-site.** One model library, one settings register, one set of conventions — and the second site costs a fraction of the first

NOTE NERC's system protection working group is currently developing a technical reference on Ethernet-based protection and control systems and how the PRC standards apply to them

PROTECTION AS A SAFETY CONTROL

Arc Flash Is a Settings Problem

Incident energy is a function of available fault current and clearing time. Only one of those is under your control after the equipment is installed.

What we deliver

- **Incident energy analysis to IEEE Std 1584**, with the model, the assumptions and the equipment configuration stated
- **Label schedules** in a form your labelling contractor can produce directly
- **Mitigation options with the trade-off shown** — a faster setting almost always costs selectivity somewhere, and the owner should see that choice rather than inherit it
- **Maintenance-mode schemes** — energy-reducing maintenance switching with local status indication, designed as a scheme with a defined operating procedure rather than a switch on a door
- **Zone-selective interlocking and differential-based reduction** where the arrangement supports it
- **Re-analysis after any change** that moves source impedance or device settings

IEEE 1584.1 — the standard for what a study must deliver

IEEE Std 1584 tells you how to calculate incident energy. IEEE Std 1584.1 specifies the scope and deliverables of an arc flash study — what has to be in it, and to what completeness. Very few arc flash proposals reference it. Asking for it is a good way to compare bids that otherwise look identical.

Where the code touches protection

- **NEC 240.87** requires arc energy reduction where a circuit breaker is rated or can be adjusted to 1,200 A or more, with accepted methods including zone-selective interlocking, differential relaying, energy-reducing maintenance switching with local status indicator, an energy-reducing active arc flash mitigation system, and instantaneous settings or overrides below the available arcing current
- **NEC 240.67** applies the equivalent requirement to fuses
- Documentation and performance testing of the chosen method are part of the requirement — the scheme has to be shown to work, not merely specified
- **NFPA 70E** governs the work practices, PPE selection and labelling regime that the study feeds

Code citations are applied against the edition your authority having jurisdiction actually enforces, which is commonly one or two cycles behind the published edition. We confirm that at the start rather than assume it.

THE CONNECTION MOST OWNERS MISS

One model, three answers

The short circuit model that produces your coordination study also produces your arc flash results and supports your equipment duty verification. When those three come from one model maintained by one firm, a system change updates all three together. When they come from three studies done years apart by different firms, they diverge quietly — and the divergence is usually discovered during an incident investigation.

The trade-off is real and it belongs to the owner. Faster clearing lowers incident energy and costs selectivity. We show both numbers and let the owner decide, rather than quietly optimising for one

Maintenance mode is a scheme, not a switch. It needs a defined operating procedure, status indication, a way to confirm it is active, and a way to confirm it was returned — or it becomes a setting left in the wrong state

Labels go stale

An arc flash label states a result calculated from a model of the system as it was. Add generation, change a transformer, upgrade a source, adjust a setting, and the label on the door is now wrong — in whichever direction. Re-analysis after change is not a service upsell; it is the only thing that keeps the label meaningful, and it is far cheaper than the first study because the model already exists.

WORKING INSIDE YOUR CONTROLS

The Cyber Boundary, Named Before We Start

At qualifying facilities your relays, RTUs and gateways are BES Cyber Assets. Everything we do to them happens inside your programme, not around it.

Where CIP reaches protection assets

- CIP-002 categorisation decides whether your protection and control cyber assets are in scope. Criteria that reach substation protection include transmission facilities at **500 kV and above**; 200 to 499 kV substations connected to three or more other stations above a weighted threshold; facilities critical to interconnection reliability operating limits; facilities essential to nuclear plant interface requirements; and generation interconnection, remedial action scheme and load shedding systems
- Substations below those thresholds fall to **low impact** — which is a category, not an exemption
- Settings changes, firmware updates and remote access to in-scope devices sit inside your change management, patch management and electronic access controls

Our position, stated in the scope of work

We design and deliver protection engineering to be executed within your CIP change-management, patch and electronic-access controls, working to your procedures with your approvals. **We do not provide CIP compliance services and we do not act as your CIP responsible entity.** That boundary is named in the scope of work rather than discovered when a change request reaches your compliance team.

How we take the work

- **Defined scope.** A named deliverable — a settings package, a scheme design, an arc flash study, a RAS documentation package — with a fixed fee and stated inputs
- **Within your programme.** Task-order or staff-augmentation engineering performed to your procedures, with your checking and approval — the standard route where the work touches in-scope assets
- **Subcontract to a prime.** Protection scope delivered into an architect-engineer, EPC or OEM carrying the overall responsibility
- **Programme support.** Retained engineering across a fleet, carrying one model library and one settings register rather than rebuilding both per site

What we need to start

- One-line and three-line diagrams, and the relay list with models and firmware versions
- Existing short circuit and coordination models, with their vintage
- Current setting files or setting sheets, as-left where available
- CT and VT ratios, accuracy classes and burdens
- Your protection philosophy or design standard, if you have one
- The driver — a replacement, a new terminal, a finding, an event or an audit date

Why we lead with this

Because a firm that answers the CIP question vaguely is telling you something. Protection engineering touches assets inside a regulated security perimeter, and the boundary between what an outside engineer designs and what the responsible entity approves and executes has to be settled before the first change request, not after it. Knowing exactly which side of the line a deliverable sits on is part of the competence being purchased.

Low impact is a category, not an exemption. Substations below the medium-impact thresholds still carry obligations, and a settings change process that ignores them is a finding waiting to happen

Remote access is the usual friction point. How an outside engineer reads a relay, loads a setting or retrieves an event record has to be designed into the engagement, not improvised on the day

Missing data is normal and is not a barrier

Very few owners have all of the above current. Field verification, drawing reconciliation and as-found settings retrieval can be the first phase of the work, priced and scoped as such — which is a better outcome than a study built on a model nobody has checked against the plant since it was commissioned.

MISSING SOME OF IT IS NORMAL Data gathering and field verification can be the first phase of the work — and we say so in the proposal rather than discover it later

WHO WE WORK FOR AND HOW

Engagement & Capability

WHO COMMISSIONS THIS WORK

- Investor-owned utilities
- Municipals & cooperatives
- Transmission owners
- Generator owners & IPPs
- Renewable & storage developers
- Nuclear operators
- Data center developers
- Industrial owners
- EPC contractors
- OEMs & integrators
- Testing contractors
- Architect-engineers

TYPICAL DELIVERABLES

- Protection philosophy document
- Relay setting sheets & native files
- Coordination study & curves
- Short circuit & device duty study
- Arc flash study & label schedule
- Panel design & wiring diagrams
- AC & DC schematics
- IEC 61850 SCD & configuration
- SCADA point lists & telemetry
- RAS design & Attachment 1 package
- Commissioning & test plans
- PRC evidence packages

ENGINEERING PLATFORMS

PSCAD · PSS®E · ASPEN · PSLF · DIgSILENT · etap

OUR CLIENTS

entergy · EDF power solutions · aps · AVANGRID · aypa · SIEMENS energy · octa DATA CENTER · PIKE ENGINEERING · RRC · FISHER ASSOCIATES · BRASSWATER · RISK WORK · ANTHROPIC · PAE · tenova ADVANCED TECHNOLOGIES · NLINE ENERGY · UTILITY · Austin Energy · Shermco · PRO SERV INDUSTRIAL CONTRACTORS · Solvida Design + Engineering

Delivered — a multi-year protection and control design program across seven EHV bulk supply point substations at 380 / 132 / 33 / 13.8 kV class for a national transmission utility

And — 132 kV GIS grid station primary and secondary design across three 50 MW wind projects. Clients confidential; references available under NDA

- Settings audits against a current model
- Fleet-wide settings registers
- Digital relay replacement programmes
- Misoperation cause analysis
- PRC evidence package build
- Protection philosophy documents

START HERE

Four Things and We Can Scope It

01	02	03	04
The system	**The relays**	**The driver**	**The programme**
Voltage, configuration and what is being protected.	Models, firmware and whether they are staying.	A replacement, a new terminal, a finding or an event.	Whether we work within yours or deliver as design input.

WHY KEENTEL ENGINEERING

01
The study and the setting from one firm
The short circuit model behind your settings is the model behind your arc flash and your equipment duty. One model, one set of assumptions, one answer.

02
We cite the current edition
The Buff Book was inactivated in 2021 and several C37 guides turned over recently. We name the edition in the deliverable.

03
Compliance sits beside design
Our regulatory group works alongside protection, so PRC obligations shape the setting rather than surfacing as a finding later.

04
Honest about the field boundary
We plan, witness and troubleshoot. Relay acceptance and maintenance testing belongs to accredited testing contractors, and we say so up front.

05
We will not print unverified figures
No misoperation rate NERC does not publish, no process bus adoption percentage nobody sources, no superseded synchrophasor standard.

06
P.E.-sealed and defensible
Florida-registered firm, Reg. No. 36853. Written to survive utility review, audit and incident investigation.

PRIMARY AUTHORITIES BEHIND THIS FLYER

NERC standards. The PRC family — PRC-002, 004-6, 005-6, 006, 012-2, 017-1, 019, 023, 024-4, 025, 026, 027, 028-1, 029-1 and 030-1 — together with NERC's published compliance dates for Generator Owners and Operators, and the CIP-002 categorisation criteria.

NERC reports and bulletins. The 2026 State of Reliability; the Western Interconnection inverter-based resource disturbance report covering the March to June 2024 events; the Inverter-Based Resource Performance Issues Report; the May and July 2026 standards compliance bulletins; and the System Protection and Control Working Group's current work on Ethernet-based protection and control.

IEEE and IEC. IEEE C37.91, C37.96, C37.102, C37.113, C37.119, C37.230, C37.233, C37.234 and C37.243; the IEEE 3004 series following the inactivation of IEEE Std 242; IEEE Std 1584 and 1584.1; IEC/IEEE 60255-118-1; and the IEC 61850 series as published with current amendments.

Testing and code. ANSI/NETA ATS-2025 and MTS-2023; NFPA 70 and NFPA 70E as adopted by the authority having jurisdiction; and EPRI's published digital substation programme material.

Regional data. ReliabilityFirst's 2025 Misoperation Assessment, covering the ReliabilityFirst footprint for 2020–2024 — identified as regional rather than continent-wide wherever cited.

Standard versions, effective dates and figures are current as of August 2026 and provided for orientation only. Nothing here is legal or regulatory advice. The applicable Reliability Standards, your registered functions, and the code edition enforced by your authority having jurisdiction control.

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