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Via Norwich to Tilbury DCO Portal

Our ref: CC33/CC33/UK01-000162-00331/136600279 v2

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26 January 2026

Dear Planning Inspectorate

Request to participate in Compulsory Acquisition Hearing 1 (CAH1) and request to participate in issue specific hearing 1 (ISH1) in relation to the Norwich to Tilbury Development Consent Order (Application Reference: EN020027) (the "Application") submitted by National Grid Electricity Transmission (the "Applicant")

Interested Party Reference: [redacted]

1. Background

Fieldfisher LLP ("**Fieldfisher**") continue to act for the British Pipeline Agency Limited ("**BPA**") as agents for United Kingdom Oil Pipelines Limited ("**UKOP**").

On 26 November 2025, Fieldfisher, for and on behalf of BPA and UKOP, submitted a relevant representation in respect of the Application with registration number [redacted] (the "**Relevant Representation**"). The Relevant Representation is examination document **RR-0413**.

Terms in this correspondence shall have the meaning as defined in the Relevant Representation unless otherwise defined.

UKOP is the owner of the Pipeline together with the beneficiary of the land rights relating to the Pipeline and BPA is employed as agent by UKOP to operate and maintain the Pipeline and to act on its behalf in respect of this DCO process.

2. Request to participate in CAH1 and ISH1

Further to the Relevant Representation, Fieldfisher request to participate in both compulsory acquisition hearing 1 (CAH1) and issue specific hearing 1 (ISH1) on behalf of BPA / UKOP.

CAH1 is due to be held on 11 February 2026 and ISH1 is due to be held on 13 February 2026.

We set out further detail in respect of each hearing below.

2.1 CAH1

(a) **Attendees**: [redacted] of Fieldfisher LLP, Riverbank House, 2 Swan Lane, London, EC4R 3TT ([redacted]fieldfisher.com / [redacted]), speaking online only.

(b) **Submission Topics:**

The submission will refer to matters set out in RR-0413. In addition, (where relevant) it will address the following matters:

(i) Compulsory Acquisition and Temporary Possession

(A) Adequacy of Consultation and the need to ensure robust protections (both practical and in legal rights' terms) for the ongoing use and maintenance of the Pipeline.

(B) The Applicant's compliance with section 122 of the Planning Act 2008 ("**PA 2008**") together with the Department for Communities and Local Government's September 2013 guidance relating to procedures for the compulsory acquisition of land.

(C) The Applicant's consideration of the conditions set out in section 127(5) of the PA 2008 should be complied with, notwithstanding that UKOP is not a statutory undertaker as the same operational, safety and national interest arguments apply.

(D) Absent the acceptance of a relevant valid change request, the proposed acquisition of Nationally essential rights to enable UKOP to safeguard its Pipeline are significantly outside Order limits and therefore potentially undeliverable / ultra vires.

(ii) Cumulative Effects of the Project

(A) The adequacy of consultation and negotiation with UKOP (absent protective provisions or any side agreement being agreed).

(B) Consideration of the fact that UKOP is not a statutory undertaker, does not benefit from compulsory powers and therefore the crucial need to safeguard the Pipeline due to reasons of national energy security.

(C) The Applicant's compliance with the National Policy Statements published in November 2023 and designated in January 2024 (the "**NPS**") (copies enclosed).

(iii) Design of the Project

(A) The risks posed by the design of the Project (unless adequate mitigation can be guaranteed) would be contrary to National Electricity System Operator ("**NESO**") guidance and the United Kingdom Oil

Pipeline Operators Association's ("**UKOPA**") guidance in respect of AC interference on pipelines (copies of which are enclosed herein).

(iv) Health and Wellbeing / Safety and National Security

(A) The risk of AC interference caused by the Project being significantly in excess of British Safety Standards contrary to the UKOPA guidance enclosed, posing a risk both to the public and the environment (unless adequate mitigation for the effect of the overhead line on the pipeline is provided as is now proposed through the Applicants proposed application to amend Application).

(B) The risk to national fuel supplies and national fuel security by the Project.

(v) Socio-economic Effects of the Project

(A) The potential for the disruption to national fuel supplies, including the supply to nationally significant infrastructure including international airports.

2.2 ISH1

(a) **Attendees**: [redacted] of Fieldfisher LLP, Riverbank House, 2 Swan Lane, London, EC4R 3TT ([redacted]fieldfisher.com / [redacted]), speaking online only.

(b) **Submission Topics:**

3. The submission will refer to matters set out in RR-0413. In addition (where relevant) it will address the following matters:

(i) Effect of the Project

(A) The effects of alternating current (AC) interference on the Pipeline (to the extent not addressed in CAH1).

(B) The need for mitigation in respect of the Pipeline, including mitigation which may fall outside the Order limits (unless the Applicants application to amend the Application is accepted).

(C) Compliance with Article 15 of the Pipeline Safety Regulations 1996 if mitigation cannot be guaranteed.

(D) Insufficient consideration of the potential impacts of the Project's crossing of the Pipeline if the proposed mitigation that will protect the Pipeline is not delivered prior to energisation in the EIA.

(E) The paramount need to safeguard BPA / UKOP's ability to access, repair, replace, maintain and renew the Pipeline in line with its statutory and regulatory requirements and the need to safeguard its respective land interests.

4. Summary

While BPA / UKOP do not object to the Project in principle, they cannot support the draft Order in its current form until BPA / UKOP's legitimate concerns (as set out in the Relevant Representations and to be addressed at the above hearings) have been addressed.

BPA/UKOP would note that the Applicant has been engaging proactively with a view to finding solutions to these issues and working towards draft contractual protections.

However, until such time as the Applicant is able to guarantee the installation and long-term retention and upkeep of adequate mitigation and safeguards there remains a significant risk that damage to the Pipeline will be caused due to accelerated corrosion, resulting in unacceptable levels of risk to (inter alia)

(a) the public and the environment due to the potential of rupture and leakage; and

(b) the safety and security and resilience of the country's nationally significant fuel infrastructure

BPA and UKOP are therefore compelled to reserve the right to (a) object to the dDCO as currently drafted and (b) make further representations during the examination process. In the meantime we continue to proactively work with the Applicant to address the matters set out above.

We thank the Planning Inspectorate for its assistance with this matter.

Yours faithfully

Fieldfisher

Fieldfisher

IChemE

0260-9576/00/$10.00 + 0.00

AC corrosion on pipelines

Trevor Osbourne
DCM UK Ltd

AC interference on pipelines is a serious problem that can pose a threat to both the safety of the operator and the integrity of the pipeline.

Induced AC on pipelines is generally a steady state condition which varies with power transmission line load and phase imbalance, however, an imbalance in the transmission system or high voltages near transmission tower grounding systems resulting from lightning strikes and phase faults will produce interference.

This problem may go undetected, with the first indication that AC is affecting a pipeline being fluctuating DC potential measurement or sometimes evidence of shock by operations personnel. In addition, pipe corrosion can also result from AC discharge. Of course, we may also be able to clearly see the source of the interference—the presence of power lines in the vicinity.

To address this problem, the pipelines must be grounded with a system that passes AC, but blocks DC, to mitigate the AC and maintain the cathodic protection on the pipeline. This article gives an overview of the techniques required to identify and mitigate AC corrosion.

Identification techniques

Types of coupling

Three main types of coupling between AC transmission systems and pipelines can occur:

- Capacitive coupling occurs when a strung and welded pipeline lies parallel to overhead power lines and may give rise to dangerously high potentials unless the pipeline is properly grounded. This effect is not significant once the pipeline is buried since the electrostatic charge is effectively grounded.
- Inductive coupling is brought about by the magnetic field surrounding the power conductors. It can be significant when a buried pipeline with a high quality coating, which reduces leakage current to a minimum, is in the presence of an overhead power transmission system. Generally, the greater the coating resistance and the higher the soil resistivity, the greater the induced AC potential.
- Where grounded AC power systems share a common electrolyte with other underground or submerged structures, current may flow in these structures due to AC ground faults. Such faults may occur due to cable breakage and 'arcing-over' at insulators during lightning strikes and wet conditions. This will cause a rise in the potential of the surrounding earth (ground potential rise) and a pipeline passing through an area when experiencing such a fault may suffer coating damage or possible pipe wall penetration.

Once the problem is recognized, it is important to determine whether there is likely to be a safety risk to personnel and to establish how likely AC corrosion is to occur.

For AC corrosion, the most important form of coupling is inductive coupling which can be termed the steady state condition. However, resistive coupling also plays a part in that coating damage caused during fault conditions may then lead on to corrosion damage, both AC and DC.

Survey activities for AC corrosion detection

To assess if mitigation is required to prevent the initiation or continuation of AC corrosion, we need to:

- measure cathodic protection (CP) potentials and rectifier outputs to establish that the CP system is operating correctly;
- establish the AC potential on the pipeline;
- log data at location where induced AC potentials are measured to provide greater time-scale based data using a logging rate that allows full analysis;
- measure soil resistivity to and beyond pipe depth (4 pin Wenner method or electromagnetic techniques);
- carry out a detailed coating defect survey in the areas of concern to locate all coating defects in the range 1 to 3% (%IR) using direct current voltage gradient (DCVG) technique, mark location of all defects;
- install coupons of known surface area (optimum 1 cm^2) and log current flow onto coupon to obtain current density information.

From the above we can establish:
- the CP system is operative and working at optimum efficiency;
- the magnitude and location of induced AC potentials;
- any time-dependent variations in the induced AC;
- the soil resistivity and what that can tell us about the propensity for the soil to support corrosion;
- the presence or otherwise of coating defects (hollidays) and an approximation of their size (1 cm^2 being optimum);
- from coupon data, the current density likely to be seen and for what percentage of the time.

AC current densities

The most influential problem in AC corrosion is the presence of coating defects. If the coating were perfect then there is unlikely to be an AC corrosion problem. If the DCVG reveals coating defects and the coupon data indicates that AC current densities can be measured, we need to quantify the problem. To do this we need to be aware of the critical levels of AC current density. These can be summarized as:

20A/m^2	No corrosion
20 to 100A/m^2	Corrosion is unpredictable
100 A/m^2 and greater	Corrosion is expected.

Confirming the presence of AC corrosion

Having carried out the above steps, the next step is to excavate the pipe to verify its condition. The following steps are recommended:
- locate the anomaly (using DCVG techniques, as described above) and carefully excavate it, being careful not to disturb the soil directly surrounding the area of the holliday or any corrosion products;
- measure the DC and AC potentials at several stages of the excavation;
- obtain soil samples immediately adjacent to the anomaly and from the side of the excavation at pipe depth and determine:
  - ○ soil resistivity;
  - ○ moisture content;
  - ○ pH;
  - • chlorides:
  - ○ sulphides;
  - ○ any special attributes that the soil may have.
- take photographs at all stages, particularly of the anomaly upon first exposure;
- examine the condition of the coating and determine if the anomaly may have been shielded from CP current;
- measure the potential at the anomaly by placing a reference electrode immediately on top of any corrosion products;
- using a combination pH/reference meter and micro-electrode, measure the pH and potential at the bottom of the pit;
- remove the corrosion product from the pit and conduct tests to determine:
  - ○ pH;
  - ○ chloride ion concentration;
  - ○ sulphide ion concentration;
  - ○ sulphate reducing bacteria concentration.
- photograph the pit after cleaning it and record dimensions.

Is it AC corrosion?

After gathering the above data, the following analysis should be conducted to determine whether AC corrosion or some other form of corrosion was the primary cause of the pit:
- Determine whether the pit was cathodically protected.
- Determine whether the pit could have been caused by bacterial corrosion.
- If the pit appears to have received adequate CP over the pipeline life to date and if bacterial activity plays no part, then the possibility of AC corrosion should be investigated. Calculate the current density at the pit from the pit dimensions, soil resistivity and AC potential.
- Consider the appearance of the pit, i.e. did it have:
  - ○ hard hemisphere of soil surrounding the pit;
  - ○ smooth round dish-shaped pits having a minimum diameter of approximately 1 cm^2;
  - ○ hard tubercles covering the pit.

If all other causes can be eliminated it is probable that the corrosion is due to the effects of AC.

Summary

Although there is a lack of information on the mechanism of AC corrosion, it is apparent that AC can cause corrosion of buried steel pipelines even in the presence of a correctly designed and operated CP system. However, the following is known:
- AC corrosion increases with current densities greater than 20 A/m^2 and is said to be significant at current densities greater than 100 A/m^2 regardless of CP current density.
- AC corrosion increases with duration or chloride content in soil or water environments.
- AC corrosion increases with decreasing holliday surface area reaching a maximum for a holliday of around 1 cm^2.
- AC corrosion increases with decreasing frequency below about 100 Hz.
- AC corrosion decreases with increasing CP current density, but is not eradicated.
- AC corrosion appears to decrease with time.

For the aforementioned factors, it would be sensible for operators to reduce AC current densities (by controlling AC voltage) below 100 A/m^2 for a 1 cm^2 holliday to prevent AC corrosion especially in deaerated or chloride-containing soils and waters.

Mitigation techniques

Having established that there is a problem with AC on a particular pipeline and that it has already or may in the future cause a corrosion problem, mitigation should be considered.

Mitigation of steady state induced AC to prevent corrosion should be seen in the wider context of mitigation for the conductive as well as inductive cases. It is often the case that if the conductive condition is addressed and mitigated then the inductive condition will also be provided for.

A number of methods have been used to mitigate both induced and conductive coupling. Three of these methods will now be discussed further.

Spot or lumped grounding

Spot or lumped grounding is probably the simplest and most commonly used method of lowering the AC interference potential of a pipeline. One simply connects the pipeline to a low impedance ground path. If the impedance is made low enough at the point of connection to the pipeline then the AC potential will be decreased locally to almost any level required. The main disadvantage is that large grounding systems are required to attain the required impedance.

In addition, the effectiveness of such installations is strictly local and to mitigate using such a system in high resistivity soils requires multiple installations along the affected pipeline segment and cannot address all the problems associated with induced AC voltage (e.g., it will not prevent pipeline coatings from being over-stressed).

Where soil resistivities are very low (10 ohm metre or less) the lumped method can result in satisfactory protection, if installed regularly. However, these levels of soil resistivity are more the exception than the rule.

Another aspect is the effect of such systems on the pipeline's CP system. If it is acceptable to the pipeline owner/operator to have either zinc or magnesium rods directly coupled to the pipeline then these materials will supplement the existing CP system. However, they will be consumed within a period of time proportional to the current delivered and weight of material installed, and may require future replacement to ensure continued protection against induced AC.

If the owner/operator wishes to have a mitigation system that has zero effect on the pipeline's cathodic protection system and one that provides continuous AC coupling and DC blocking, a polarization cell is required.

Cancellation wires

This technique consists of burying long wires parallel to the power transmission line on the opposite side of the pipeline and continuing along the transmission line right of way beyond the points where the pipeline deviates from the common right of way. By doing so, the wires become subject to interference from the transmission lines. With careful positioning of the wires the induced voltages are out of phase with the voltage induced on the pipeline. By connecting one end of the wire to the pipeline, the out of phase voltage on the wire will cancel the voltage induced on the pipe. The other end of the wire is left free.

The disadvantages with cancellation wires are:

- they are only suitable to mitigate magnetically induced voltages and not for conductive fault conditions;
- wire can export high potentials to its free end;
- where the wires cross beneath the power line it increases exposure of the pipeline to direct energization from fallen power lines or fault conditions;
- requires purchase or lease of additional land outside of pipeline right of way.

Gradient control wires

Gradient control wires consist of one or more bare metallic conductors of zinc, copper or galvanized steel with and without backfill materials (chemical backfill, bentonite, gypsum mix, metallurgical coke breeze or calcined petroleum coke breeze). They are buried parallel with and close to the pipeline (0.5 to 1 metre depending upon the trench dimensions) with regular connection points made between the pipe and the gradient control wires. The wires are effective in both the inductive and conductive cases.

Gradient control wires work by evening out the pipeline and soil potential differences. In the inductive case, gradient control wires provide additional grounding for the pipeline thereby decreasing the induced pipeline potential rise. At the same time they sharply reduce touch and coating stress voltages. However, locations on pipelines where personnel have access (e.g. valves, AGI piping) should be considered as individual cases and gradient control mats considered for both normal and abnormal system conditions.

In the case of conductive interference, gradient control wires dampen the ground potential rise in the locality of the pipe. At the same time pipe potentials are raised resulting in reduced touch and coating stress voltages.

Gradient control wires materials

When gradient control wires are made of zinc they act in the same manner as a sacrificial anode and can supply cathodic protection for the sections of pipeline to which they are attached. However, connection of zinc directly to the pipeline can impact ability to carry out DCVG and CIPS surveys. Connection of other and less expensive materials to the pipe (e.g. copper and galvanized steel) are possible but must be connected through a polarization cell in the same manner as described earlier for spot mitigation to prevent cathodic protection system current losses.

Whichever material is used to provide mitigation using gradient control wires it is desirable to connect them through a polarization cell to facilitate the ability to carry out DCVG and CIPS surveys and to isolate the mitigation system from the CP system.

Another consideration when designing a mitigation system is the presence of DC interference. This may be present due to other CP systems in the locality or from DC traction systems. Any material directly coupled to the pipeline for the purpose of AC mitigation will allow easy passage of DC interference onto the pipeline, which then may discharge elsewhere causing a corrosion problem. Polarization cells possess suitable DC blocking characteristics that will help prevent this from happening.

If it is considered viable to install polarization cells then the use of costly anode materials such as zinc and magnesium can be replaced with cheaper copper and steel alternatives.

Fault current case

Even when the induced AC voltage is below the 15-volt level under normal system conditions, analysis is warranted to determine whether potentially hazardous conditions exist under abnormal system operation. This analysis requires access to specialized software and knowledge in using this software. Whenever mitigation is warranted, the voltages and currents associated with abnormal power system conditions should also be analysed as these conditions may present the greater risk of damage to equipment and harm to personnel. Fault conditions may also create new or enlarge existing coating hollidays, which in turn may lead to AC corrosion under steady state conditions in the future.

Installation of gradient control wires

- One or two gradient control wires may be used. They should be placed parallel to the pipeline and connected to it at intervals.
- The connection interval and the length of each segment will determine the magnitude of both the steady-state current and fault current that will flow into a given segment.
- These parameters can be selected to minimize the overall mitigation system cost by using software specifically developed for designing AC mitigation systems. Connection intervals typically vary from about 200 to 600 metres.

Effect of gradient control wires

- Gradient control wires prevent the pipeline coating from being electrically overstressed during abnormal power system conditions along the mitigated section of pipeline.
- They minimize the possibility of arcing damage to the pipeline due to high potentials during abnormal power system conditions.
- They minimize both touch and step potentials along the entire pipeline (though gradient control mats are still recommended at above ground worker access sites).
- They may or may not assist in cathodic protection of the pipeline depending on the mitigation design and material selected for the gradient control wires.

Gradient control wire material options

The following factors should be considered when selecting a gradient control wire material. The material selected should:

- not interfere with the cathodic protection design for the pipeline or the ability to subsequently take pipeline potential measurements;
- result in the lowest installed cost for the mitigation system and the cathodic protection system;
- provide low and stable conductor impedance to earth in order to minimize the potentials around the pipeline, particularly under abnormal power systems conditions;
- carry the required AC fault current under abnormal conditions.

Zinc versus copper gradient control wires

As previously mentioned, zinc has been the material traditionally used for gradient control wires. More recently, copper has been used as it offers economic and other benefits. The advantages and disadvantages of zinc and copper can be summarized as follows:

- Zinc advantages:
  - May provide supplemental cathodic protection, but most often used in conjunction with an impressed current cathodic protection system.
  - Can be bonded directly to the pipeline without the need for a polarization cell. (Connections should be made through an above ground junction box, as future access may be required).
- Zinc disadvantages:
  - IR free readings cannot be taken when zinc is bonded directly to the pipeline.
  - DCVG surveys cannot be effectively carried out.
  - Stray DC current (e.g., from DC transit systems, other impressed current protection systems, etc.) can access the pipeline through the direct zinc-to-pipeline bonds, but may exit the pipeline where no zinc conductor exists, thereby creating a corrosion problem.
  - The effectiveness of zinc, when used both as an AC grounding conductor and an anode, may deteriorate with time due to surface passivation in certain soil conditions, and from being consumed as an anode.
  - A backfill may be required in certain soils.
  - The long-term fault current capability for zinc gradient control wires is not known. There is no published fault current data available.

Note: The first three disadvantages can be eliminated by connecting the zinc to the pipeline through a polarization cell.

- Copper advantages:
  - Extensively used in the electric power industry, with a long and successful history.
  - Less material is required per unit length to achieve comparable mitigation results because copper is highly conductive, corrosion resistant, and is not consumed as an anode (i.e. it is DC isolated).
  - Enables instant OFF cathodic potential measurements to be taken.
  - Enables post lay and future coating defect surveys without need for disconnection of AC mitigation measures.
  - The potential adverse effects of stray DC currents are eliminated because access to the pipeline is blocked by the polarization cell.
- Copper disadvantages:
  - Care must be taken to avoid direct contact between copper gradient control wires and the steel pipeline during installation.
  - The requirement for a polarization cell may result in added cost (versus bonded zinc) if the mitigation design is not optimized for isolated gradient control wires.
  - A backfill may be required in certain soils.

Summary

There are several factors to consider in selecting a mitigation system for dealing with AC voltages and currents in pipelines. The mitigation system should:

- consider the effects of both normal and abnormal power system conditions;
- fully integrate with the cathodic protection system;
- minimize the introduction of secondary problems;
- allow instant OFF potential measurements;
- eliminate potential pipeline corrosion due to stray DC currents;
- simplify interfaces by addressing the cathodic protection system and the voltage mitigation system as separate systems.

Electrical Safety Aspects of AC Interference on Pipelines

By

[redacted] to

UKOPA 16^{th} May 2018

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AC Interference on Pipelines

- AC interference on pipelines can cause AC corrosion under certain conditions, which can affect pipeline integrity and result in high rates of corrosion on pipelines that have effective levels of CP.
- However, AC interference on pipelines can also have consequences for personnel safety by creating a touch and step potential electrical shock risk during pipeline construction, operation, maintenance and repair
- It can also affect pipeline CP system operation and the ability to conduct over the line surveys

Presentation Aims

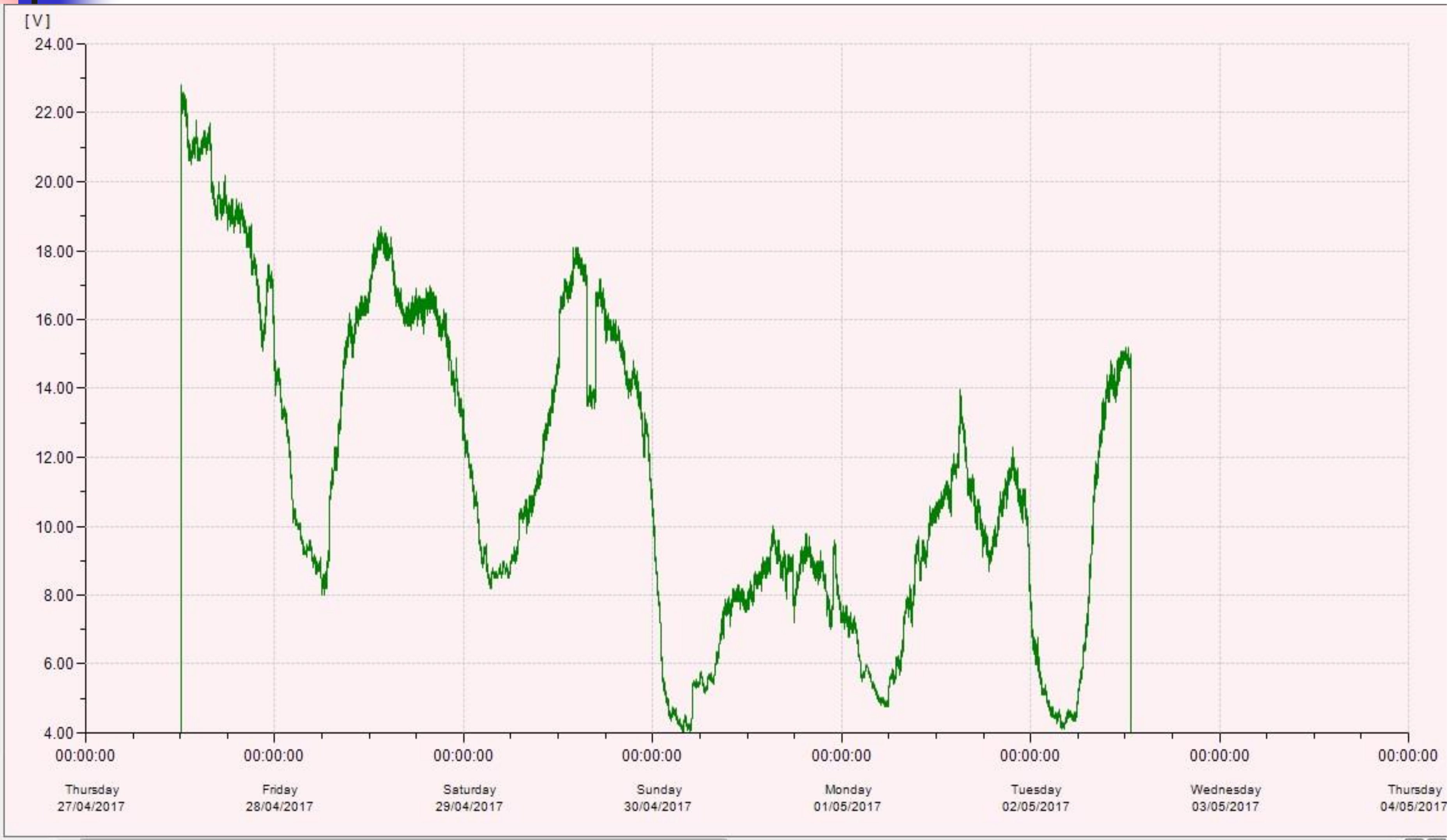
- Identify the electrical risks associated with working on pipelines in close proximity to overhead powerlines, which should be considered during design, construction and operation.
- Provide clarity and guidance on the permissible long term and short term voltage levels and identify deficiencies in existing standards in relation to permissible voltage levels.
- Discuss specific situations that may give rise to risk e.g. incendive ignition risks in AGIs at IJs, use of surge protection , proximity distances between electrical power sources and pipelines etc
- Identify applicable reference standards

Pipeline AC Interference

- There are two main types of AC interference on pipelines which occur from coupling either inductive, resistive or capacitive between powerlines and pipelines.
  - **Long term interference** i.e. AC voltages induced on pipelines routed close to powerlines via low frequency induction (LFI) that may result in varying voltages on a pipeline between 0 to 100Vrms. The voltage limit may be present for prolonged periods of time i.e. greater than 24 hours
  - **Short term voltage** i.e. voltage transferred to pipeline via resistive/inductive coupling could approach a few thousand volts and would be present for the period of time it takes the fault to clear generally less than 200ms for HV systems up to 132kV or longer up to 1 second for lower HV voltage sources

Long Term Electromagnetic Inductive Coupling

Long Term Voltage Levels



IACS

Corrosion Engineering Ltd.

AC Transmission Fault Conditions

- When fault conditions occur on a transmission line, voltages and currents can be induced on buried pipeline systems with values up to 2000V or greater possible for the duration of the fault in very close proximity to a pylon

Pipeline CP System Transformer Rectifier (TR) Unit

TR Unit After Lightning Hits Pipeline

The photograph shows the condition of a CP TR unit after the pipeline it was protecting was hit by a voltage surge.

The CP TR negative cable is connected directly to the pipeline

This photo helps to demonstrate the fact that during fault conditions there is a considerable amount of energy available.

If anyone was working on the TR or the pipeline at the time of the fault they could have suffered serious injury even death

AC Discharge Through Ionised Gases

Ionised air path due to hot gasses from heath fire

Damage to buried pipe by arc

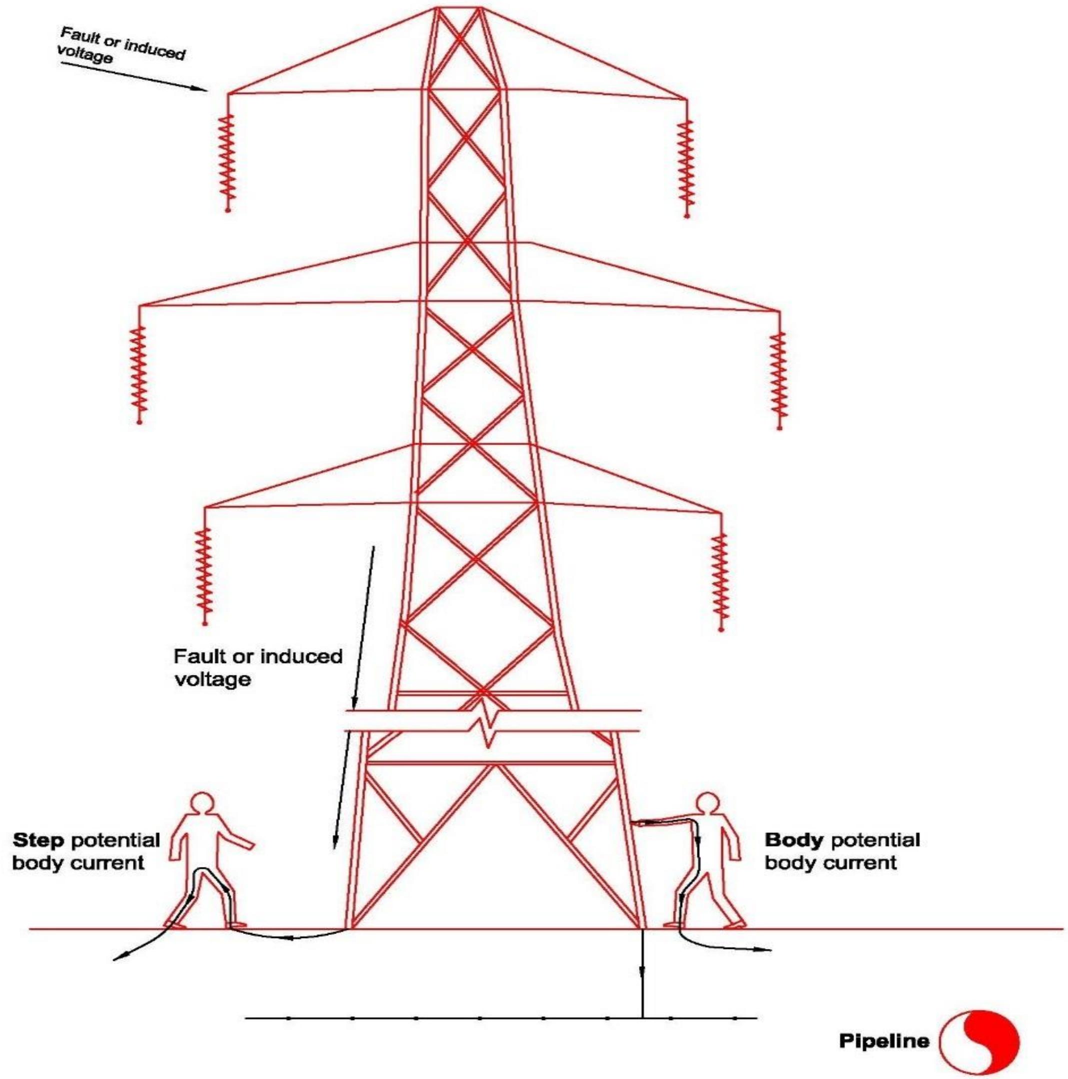
Photos Courtesy SGN

M28 Posts

M28 Post studs sometimes not insulated from reinforcing within the CP post, which acts as an earth. Current may discharge and cables appear burnt
Any operative making contact with the post at the time would be exposed to risk.
Operators need to ensure test equipment adequately protected from short circuit

Step and Touch Potential

- During fault conditions on overhead pylons high voltages can be transferred to pipelines if they are routed close a pylon.
- This risk often not considered during route selection.
- Touch potential is the voltage between the energized object and the feet of a person in contact with the object. In the case of pipelines, it is the voltage between the pipeline and the feet of anyone making electrical contact with the pipeline in contact with the ground.
- The step potential is the voltage difference across the ground that would occur when fault current flows. Step potential is the voltage between the feet of a person standing near an energized grounded object.



Touch and Step Potential- BS EN 50522

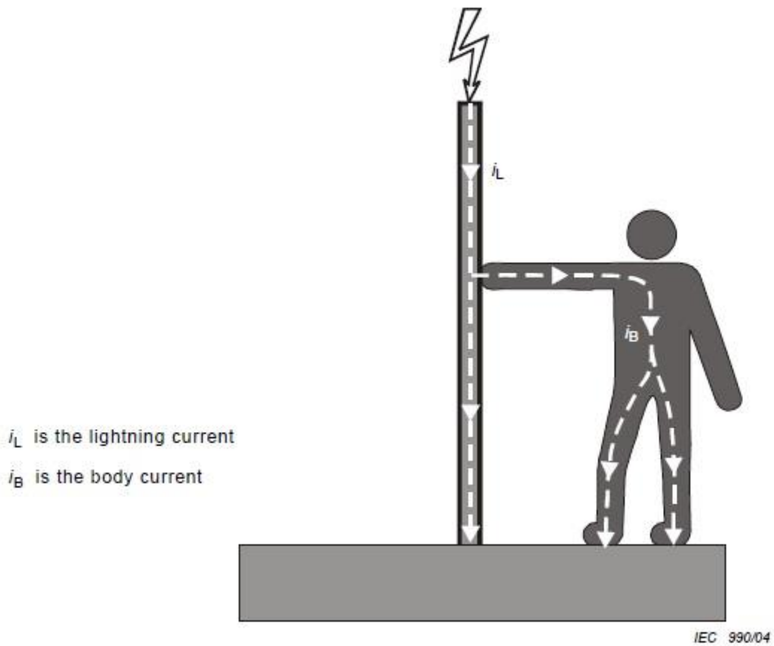


Figure A.3 – Touch voltage

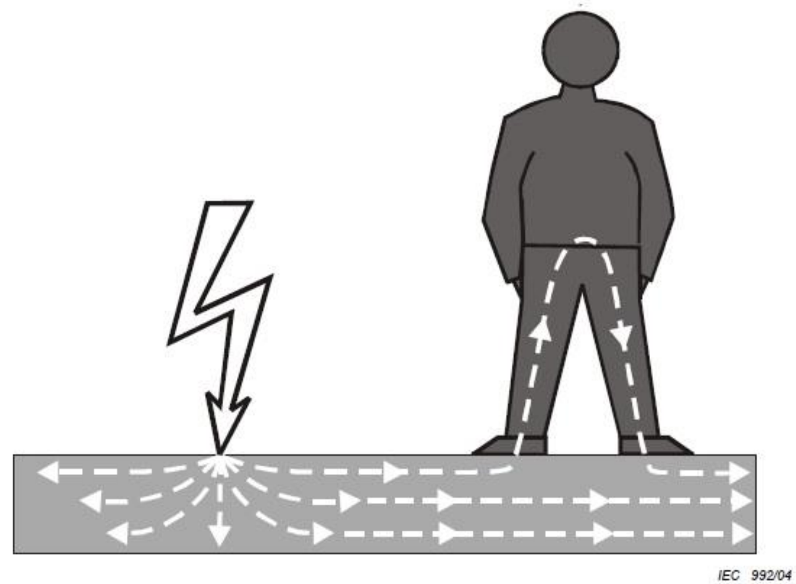


Figure A.5a – Step voltage

Overhead Pipelines Close to Powerlines

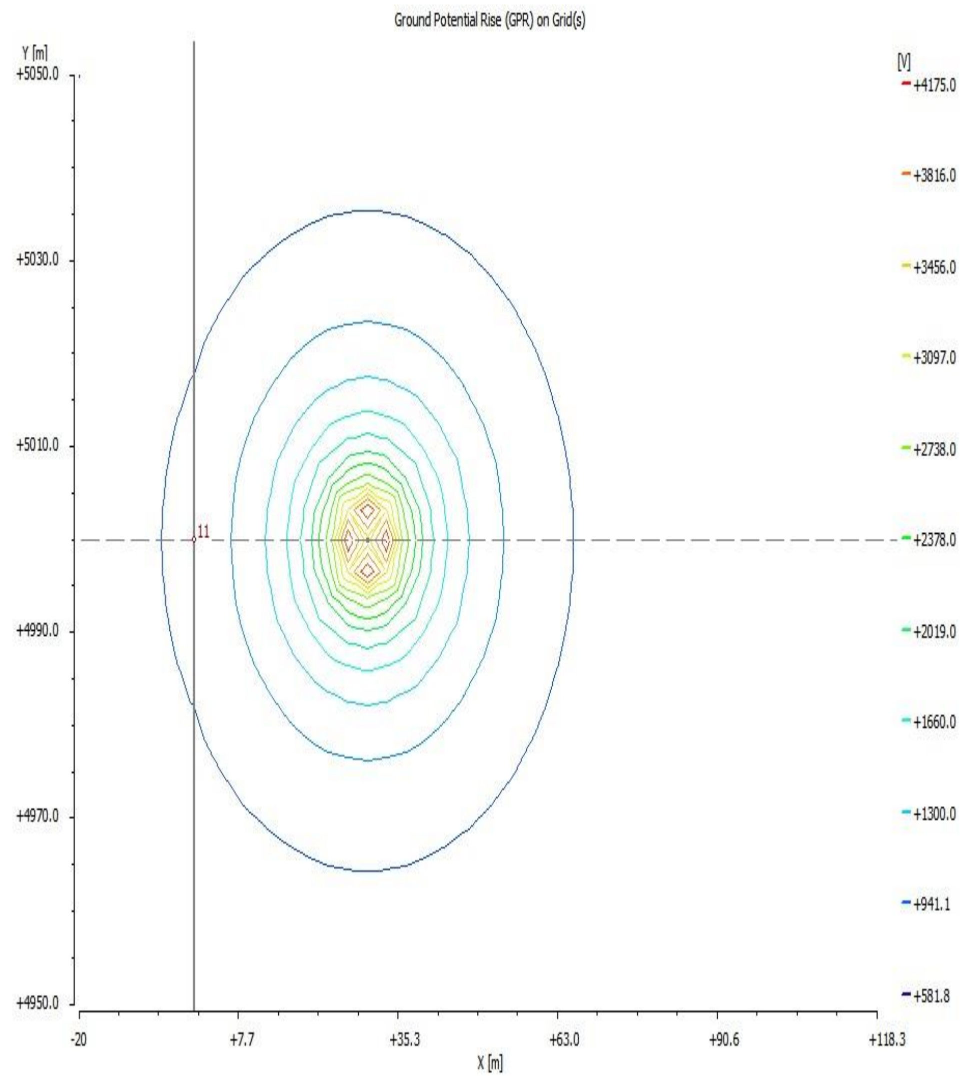
- Capacitive coupling can induce AC voltages on above ground pipelines.
- Above ground pipelines need to be effectively earthed so that if overhead power cables fall onto a pipeline then the protective devices can operate and AC voltages are safely discharged to earth.

Pipelines Close to Powerlines

- Pipelines are often routed close to powerline pylons
- There are a large number of these locations around the country.
- For any work on the pipeline system seen on the picture on the right then the touch potential risk during fault conditions should be considered
- Voltage contours during faults can be distorted and hazardous voltages can spread some distance along a pipeline from the fault location
- Operators should establish high risk touch potential locations

Pylon Earth Fault Voltage Contour Plot

- Voltage contour diagram for fault current of 10 kA within 50m of a pylon in soil of resistivity100 ohm m
- Transfer voltage on a pipeline would be about 580V at a distance of 40m from the pylon but within 10m of the pylon the voltage would about 2,300V.
- Higher soil resistivity, higher fault current then the larger the voltage contour distance.



Issues Associated with Pylons Close to Pipeline

- During fault conditions high voltages can be induced on a pipeline close to a pylon.
- These voltages could damage the pipeline coating and present a hazard to personnel working on pipelines and are dependent upon fault current, local soil resistivity and pylon to pipeline separation distance.
- Voltages in excess of 2,000V on a pipeline can damage IJs
- Personnel safe short term voltage levels vary dependent upon contact impedance and contact surface area. They also vary from nature of contact e.g. hand to foot or hand to knee
- The voltage limit may be less in certain instances and varies in different standards.
- Power system operators should ensure that fault currents will not create a HOT site in terms of electrical safety i.e. > 650V see ENA TS 41-24.
- Need to ensure personnel are aware of issues associated with work on pipelines near pylons and substations.
- Permissible voltages based upon current levels for heart fibrillation given in IEC 60479-1 now PD IEC 60479-1
- If genuine earth fault then auto reclose function means there will be 3 faults in quick succession.

Pylon Powerline Seperation

Fault Current A	Separation required (m) for two different soil resistivity values	
	100 Ω.m	**500 Ω.m**
1000	60	310
3000	190	940
6000	380	1900
10000	635	>3500

Separation distance for a touch voltage of 220V for UK requirements distance would be a lot lower because of higher permissible limits- Data from Australian Standards

Pylon Powerline Separation-650V Contour Rough Data

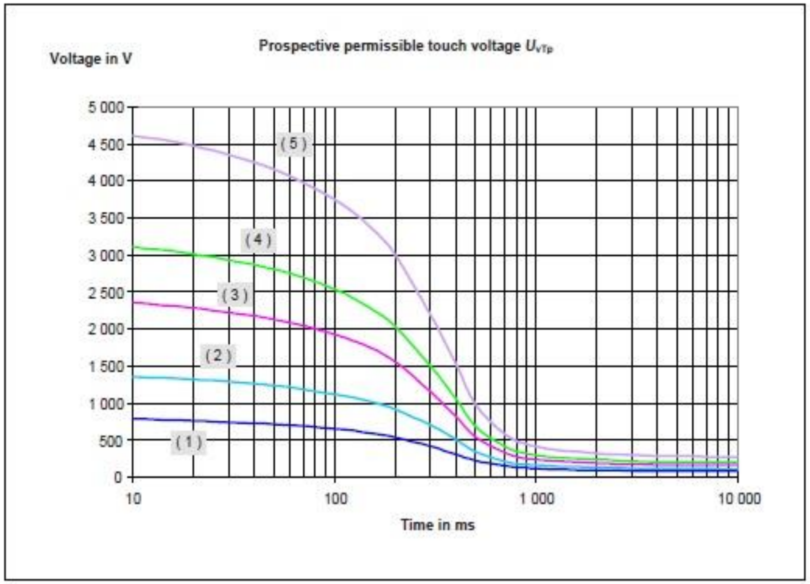
Fault Current A	Separation required (m) for two different soil resistivity values	
	100 Ω.m	**500 Ω.m**
1000	7	35
3000	15	70
6000	25	120
10000	35	180

Data above gives an approximate separation distance for a touch voltage of 650V. Values are approximate estimates accurate values will be included in the AC GPG

What is the Effect of a High Touch Voltage ?

- An unexpected low voltage electrical shock can result in an involuntary action e.g. loss of balance, dropping objects or slip.
- It is the surprise in receiving an electrical shock that can cause concern and alarm.
- It is unlikely to be fatal if less than 50V for prolonged periods or result in serious injury but can be unpleasant.
- However, the effect of the voltage will be greater if the hands are wet and personnel are not insulated from the ground.
- Hand to hand and hand to knee contact not good as low contact resistance with ground lower voltage limits.
- Step potential limits dependent upon person's weight, protective clothing and varies from person to person.

Safe Touch Potential – BS EN 50222



(1): Permissible touch voltage according Figure 4
(2): R_F = 750 Ω (R_{F1} = 0 Ω, ρ_s = 500 Ωm)
(3): R_F = 1 750 Ω (R_{F1} = 1 000 Ω, ρ_s = 500 Ωm)
(4): R_F = 2 500 Ω (R_{F1} = 1 000 Ω, ρ_s = 1 000 Ωm)
(5): R_F = 4 000 Ω (R_{F1} = 1 000 Ω, ρ_s = 2 000 Ωm)

NOTE R_{F1} = 1 000 Ω represents an average value for old and wet shoes. Higher values of footwear resistance may be used where appropriate.

Figure B.2 - Examples for curves $U_{vTp} = f(t_f)$ for different additional resistances $R_F = R_{F1} + R_{F2}$

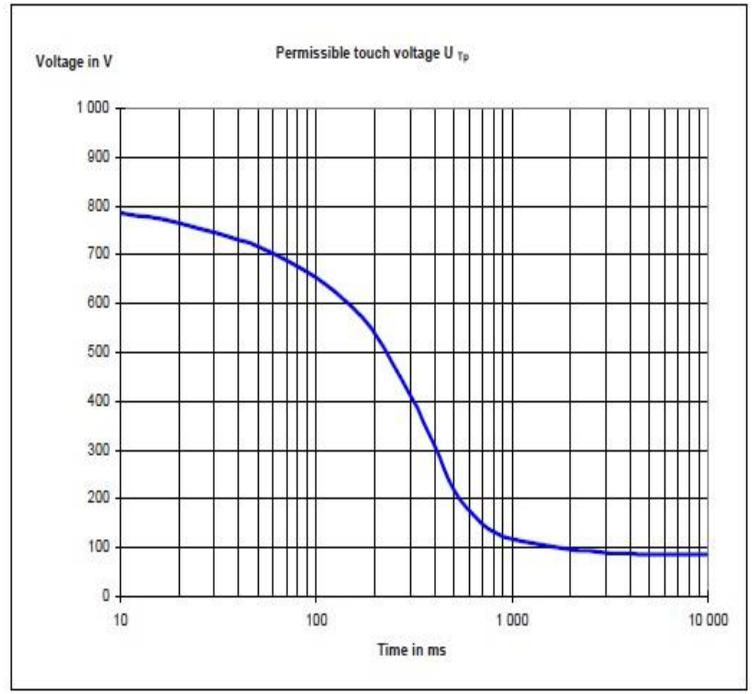


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Figure 4 - Permissible touch voltage

NOTE For duration of current flow considerably longer than 10 s a value of 80 V may be used as permissible touch voltage U_{Tp}.

PD IEC 60749-1

- Guidance on the effect current has on the human body is given in PD IEC 60749-1.
- The effects are related to current and the duration of the current flow.
- The body impedance or resistance to current flow is also dependent upon the voltage magnitude
- Higher the voltage lower body impedance it also varies across the population as well
- e.g at 200V 5% of population will have impedance of 3,500 ohms but 95% of population it will be 8,650 Ohms for wet conditions hand to hand low contcat
- Dry conditions at 25V impedance 11,125 ohms but at 200V it is 1,375 ohms for medium contact hand to

– 45 –

PD IEC/TS 60479-1:2005+A1:2016
TS 60479-1 © IEC:2005

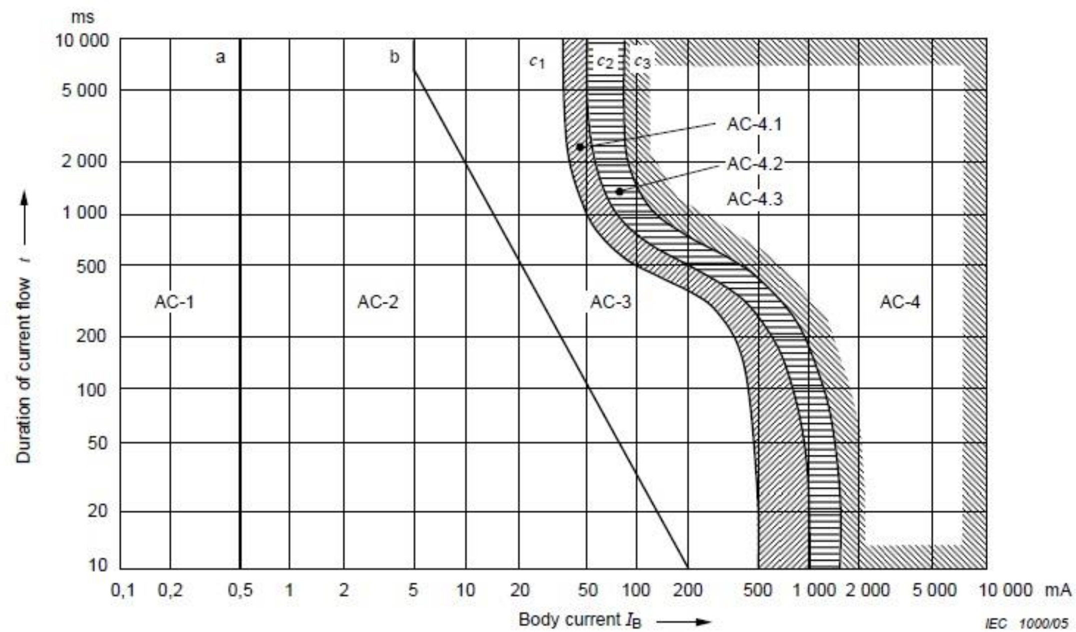


Figure 20 – Conventional time/current zones of effects of a.c. currents (15 Hz to 100 Hz) on persons for a current path corresponding to left hand to feet (for explanation see Table 11)

Current Ranges –PD IEC 60749

Table 11 – Time/current zones for a.c. 15 Hz to 100 Hz for hand to feet pathway – Summary of zones of Figure 20

Zones	Boundaries	Physiological effects
AC-1	Up to 0,5 mA curve a	Perception possible but usually no 'startled' reaction
AC-2	0,5 mA up to curve b	Perception and involuntary muscular contractions likely but usually no harmful electrical physiological effects
AC-3	Curve b and above	Strong involuntary muscular contractions. Difficulty in breathing. Reversible disturbances of heart function. Immobilization may occur. Effects increasing with current magnitude. Usually no organic damage to be expected
AC-4 [1]	Above curve c_1	Patho-physiological effects may occur such as cardiac arrest, breathing arrest, and burns or other cellular damage. Probability of ventricular fibrillation increasing with current magnitude and time
	c_1-c_2	AC-4.1 Probability of ventricular fibrillation increasing up to about 5 %
	c_2-c_3	AC-4.2 Probability of ventricular fibrillation up to about 50 %
	Beyond curve c_3	AC-4.3 Probability of ventricular fibrillation above 50 %

[1] For durations of current flow below 200 ms, ventricular fibrillation is only initiated within the vulnerable period if the relevant thresholds are surpassed. As regards ventricular fibrillation, this figure relates to the effects of current which flows in the path left hand to feet. For other current paths, the heart current factor has to be considered.

15V AC Limit on Pipelines

- The shock hazard arising from induced AC voltages has been widely recognized for many years in North America and Internationally, where the NACE SP0177 standard stipulates that an AC voltage of 15 Vrms or greater between a pipeline appurtenance and ground, which could expose a person to a touch voltage, is considered a shock hazard.

- *This requires that the touch voltage be reduced to a safe level or the pipeline be treated as a live electrical conductor. The 15 V limit was determined by multiplying 15 mA (considered the current limit below which a person could let go when grasping an electrified conductor) and 1000 Ohm (conservatively considered the human body impedance assuming a contact resistance of zero ohms).*

Touch Potential Voltage Limits

- Guidance on touch potential limits for pipelines in the UK is given in BS EN 50443.
- BS EN 50443 *electromagnetic interference on pipelines caused by high voltage a.c. electric traction systems and/or high voltage a.c. power supply systems* gives guidance on maximum touch potential limits but the levels quoted for pipelines are quite high.
- Indeed, touch potential limits in BS EN 50443 for pipelines are higher and different to the guidance adopted by other industries. Rail and telecoms industries require lower touch voltage limits.

BS EN 50443 Limitations

- Only standard to give specific guidance for pipelines on short and long term touch potentials is BS EN 50443.
- For short term interference for disconnection time of protective devices less than 200ms it is 1,500V, less than 1 second it is 430V.
- For long term interference it is 60V !!!
- BS EN 50443 voltage levels are possibly too high and are based upon electrically instructed personnel working on pipeline with a contact resistance of 3,000 ohms.
- These high voltage limits can affect personnel safety and pipeline operation. **We should not accept for pipelines in UK that a long term voltage of 60V is acceptable under any circumstances.**
- For short term interference BS EN 50122-1 for railway systems gives the touch voltage for disconnection time of protective devices less than 200ms as 645V, for disconnection times less than 1 second it is 80V.
- NACE standard for pipelines is 15V long term. BS EN 15280 for AC corrosion is risk is also maximum 15V rms.

BS EN 50443 Requirements

- The voltage values in BS EN 50443 refer to instructed persons with common clothing, without particular individual protection means other than shoes with an insulating resistance not less than 3,000 Ω.
- In case of use of individual protection means a specific study shall evaluate the admissible values for the interference voltages, which can be higher than the ones given in 10.2.2 and in 10.2.3.
- Section 10.2.2 means long term voltages above 60V and 10.2.3 means voltage less than 1,500V for a disconnection time of less than 200ms.

BS EN 50443 Requirements

- *In case of more severe situations (wet conditions, narrow working space, repairing operations, etc.) or where common people (i.e. neither electrically instructed nor skilled persons) may come in contact with the pipeline in operating conditions, additional precautions should be taken into consideration (e.g. reduce admissible voltage, use of insulating coverings, special instruction to personnel, etc).*
- *for danger to persons who come in direct contact or in contact through conductive parts with the metallic pipeline system or to the connected equipment, the voltage to earth of the pipeline and the voltage difference on the insulating joints shall be evaluated in normal operation and in fault conditions;*

Short Term Voltage Limit 200ms

Standard	Value	Comment
NACE SP 0177	Not Given	Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems
CAN/CSA-C22.3 No. 6-M91	Not Given	Principles and Practices of Electrical Coordination Between Pipelines and Electric Supply Lines
BS EN 15280	Does not cover safety	Evaluation of a.c corrosion likelihood of buried pipelines-Application to cathodically protected pipelines.
BS EN 50443	1,500 Vrms	Effects of electromagnetic interference on pipelines caused by high voltage a.c. electric traction systems and/or high voltage a.c. power supply systems
BS EN 50122-1	645 V rms	Railway applications. Fixed installations. Electrical safety, earthing and the return circuit. Protective provisions against electric shock
BS EN 50222	1,570 Vrms	Earthing of power installations exceeding 1 kV a.c
ENA TS 41-24	650V hot site 430V cold site	Guidelines for the design, Installation, Testing and Maintenance of Main Earthing Systems in Substations

Voltage Limit Long Term> 3s

Standard	Value	Comment/Title
NACE SP 0177	15V rms	Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems
CAN/CSA-C22.3 No. 6-M91	15V rms	Principles and Practices of Electrical Coordination Between Pipelines and Electric Supply Lines
BS EN 15280	15V rms	Evaluation of a.c corrosion likelihood of buried pipelines- Application to cathodically protected pipelines.(Not safety related)
BS EN 50443	60 Vrms	Effects of electromagnetic interference on pipelines caused by high voltage a.c. electric traction systems and/or high voltage a.c. power supply systems
BS EN 50122-1	60 V rms	Railway applications. Fixed installations. Electrical safety, earthing and the return circuit. Protective provisions against electric shock
BS EN 50222	65 V rms	Earthing of power installations exceeding 1 kV a.c
ENA TS 41-24	Not Given	Guidelines for the design, Installation, Testing and Maintenance of Main Earthing Systems in Substations
Low Voltage Directive – Directive 2014/35/EU	50Vrms	Not mentioned but some condition apply extra low voltage where 25V applied for hazardous conditions
BS 7671 Extra Low Voltage Systems	25Vrms	For use in specific conditions where Extra low voltages circuits where Regulation 414.4.5 does not require basic protection against electric shock for SELV and PELV circuits at less than 25 V a.c. in dry conditions or 12V a.c. for any condition. SELV is Safety extra-low voltage and PELV is Protective extra-low voltage.
SGN and T/PM/ECP/2	15V	15V limit specified

Comparison of Touch Potential Limits

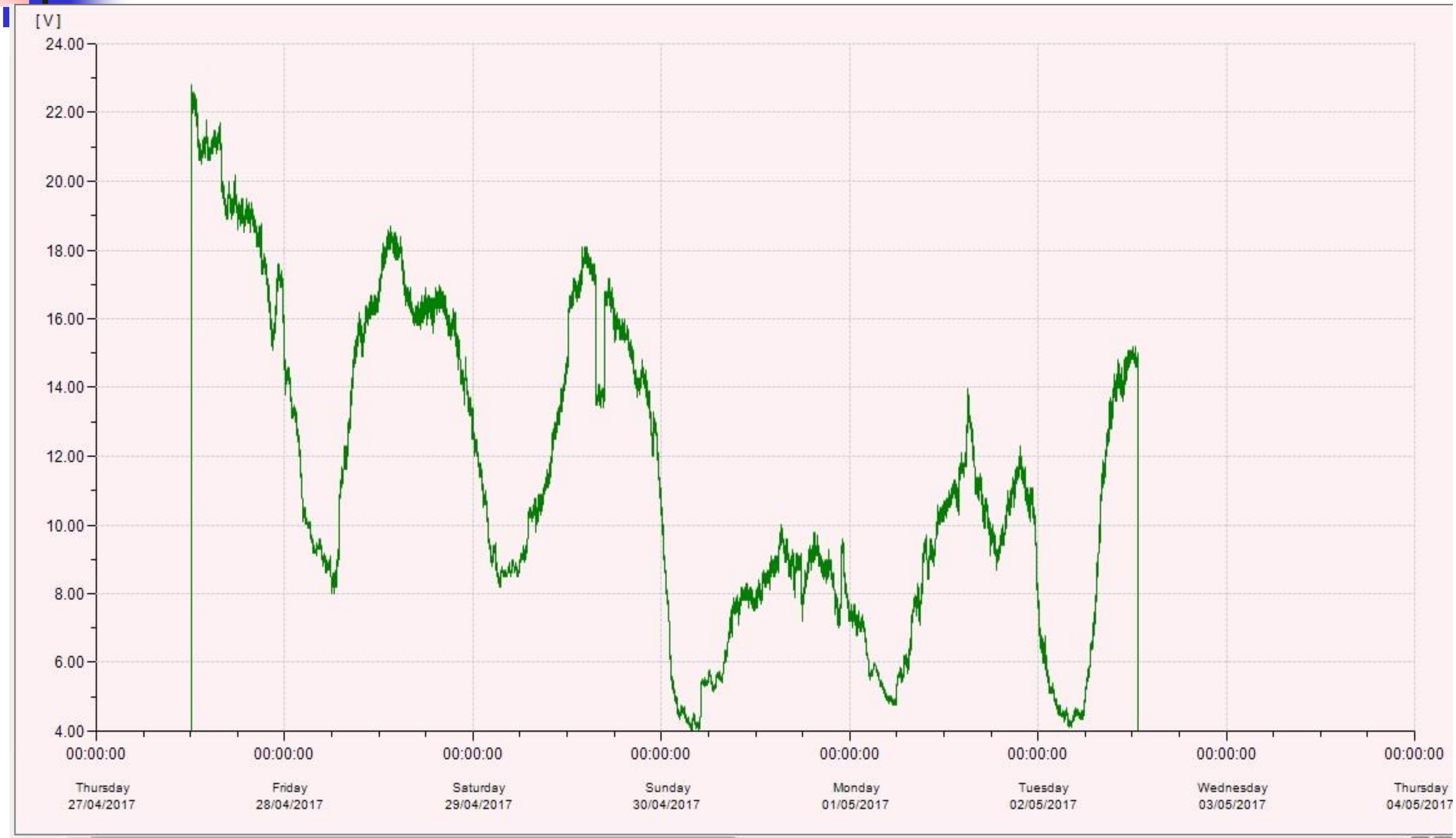
Power System Fault Duration Time (seconds)	BS EN 50443 Safe Voltage Limit (Volts)	BS EN 50122-1 Safe Voltage Limit (Volts)
< 0.1	2 000	865
0,1 < *t*o 0,2	1 500	785
0,2 < *t*o 0,35	1 000	645
0,35 < *t*o 0,5	650	480
0,5 < *t*0 1,0	430	220
1 < *t*o 3	150	75
t > 3	60	60

BS EN 50443 is the EN standard for Voltage Limits on Pipelines and BS EN 50122-1 those that the Rail Authorities require. BS EN 50443 although supposedly for pipelines imposes limits for electrical instructed personnel with a contact resistance of 3,000 Ohms . These insulation values are not applicable to most pipeline operatives or working conditions. Not sure how much UK involvement in BS EN 50443 standard development

Recommended Short Term Touch Potential Limits BS EN 50122-1

Power System Fault Duration Time (seconds)	BS EN 50122-1 Safe Voltage Limit (Volts)
< 0.02	865
0.05	835
0.10	785
0.20	645
0.30	480
0.40	295
0.50	220
0.60	155
0.70	90
0.80	85
0.90	80
1.0	75

Long Term Voltage Levels



Pipelines and Touch Voltages

- BS EN 15280 on AC corrosion limits maximum voltage to 15V rms
- BS EN 50443 gives touch voltage of 60V for periods greater than 3 seconds but this is for fault conditions. However, the standard does state that the 60V is acceptable long term.
- Long term interference AC voltage present for 24 hours a day 7 days per week on pipeline hardly fault conditions so 60V should not be accepted by the UK pipeline industry.
- Pipelines with voltages greater than 50V would be classed as live conductors under the IET wiring regulations. Yet to comply with BS EN 50443 60V is permitted? It does not make sense !
- Extra low voltages circuits where Regulation 414.4.5 of BS 7671 does not require basic protection against electric shock for SELV and PELV circuits at less than 25 V a.c. in dry conditions or 12V a.c. for any condition. SELV is Safety extra-low voltage and PELV is Protective extra-low voltage . Voltage limit here is 25V

Touch Potentials for Low Voltages

- For pipelines close to power cable systems < 66 kV where the disconnection time is less than 1 second then the maximum touch potential should lower than the 650V limit given in ENA TS 41-24
- The maximum touch potential should be based upon BS EN 50122-1 for less than 1 second it is 80V.
- Expert guidance should be sought for new installations

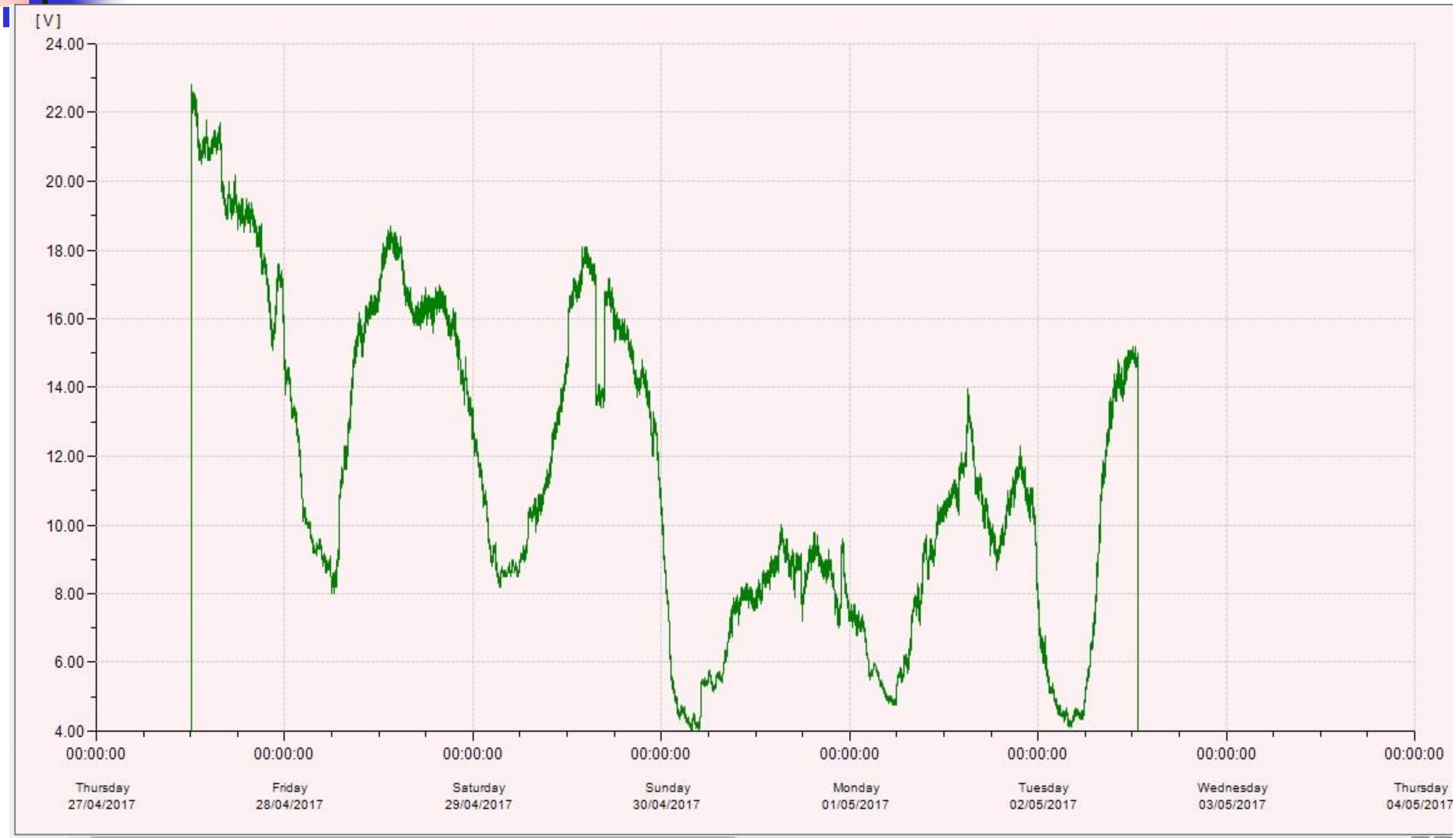
Touch Potential Limits

- Internationally 15V rms is the AC touch voltage limit for pipelines.
- *15V is the long term limit in BS EN 15280 but that standard does not relate to safety but AC corrosion risk.*
- BS/EN touch potential standards relate to safety provide higher values up to 60V
- There is a need for clarity on the permissible levels of touch voltage

Why Keep AC Voltage on Pipelines Low ?

- 15V on pipeline would not create a hazardous situation in terms of electrical shock but could result in an involuntary action i.e. slip/trip or fall.
- General public can come in contact with pipeline appurtenances
- AC present on pipelines can be rectified by variac controlled TR units and produce a fluctuating DC current and pipe to soil potential. 15V present would cause fluctuating potentials but if 60V was present there would be more DC current produced by TR units and significant changes in pipe potential.
- CIP surveys can be affected by AC interference, as AC rejection ability on CIP data loggers can vary and give misleading survey results
- 15V also historically used as maximum touch potential as if 15V was measured one day at a CP post it could be different the next day. The fact that high voltage was measured indicates a risk and if 15V is used as the base level and the voltage levels increase there is some safety tolerance
- AC corrosion could occur at voltages .Soil resistivity can vary quite considerably along pipeline route. BS EN 15280 requires AC voltage to be less than 15V to mitigate AC corrosion risk

Long Term Voltage Levels



Summary Touch Potentials

- Pipeline industry needs clarity on safe values to adopt for both short term and long term voltage levels as there is not clarity in existing BS/EN standards.
- Existing BS/EN standards have been developed by electrical engineers without taking cognisance of other associated effects from AC interference on pipelines and give relatively high and varying touch potential limits.
- Most likely that there a number of locations on many existing pipeline systems where touch potentials during fault conditions exceed safe limits.
- The number of such locations could run into a few hundred or more

Safety Issues and Specific Situations

Aspects Associated with AC on Pipelines

item	Topic	Comment
1.0	AC voltage difference each side of IJ or IF	If Polarisation Cell Replacements (PCR)s not employed at I/Js then there could be a spark hazard if insulating device e.g. IF/IJ accidentally short circuited. This could create incendive ignition risk if short circuited as available current could be quite high
2.0	High AC voltage can affect control of CP TR units	Higher AC voltage present on pipeline greater variation in DC current out from CP TR units so problems associated with control of CP systems increase with increase in AC voltage
3.0	Pipe location	Pipe depth and location by radio frequency devices difficult near overhead power lines if high levels of AC present can assist with location but also interfere with location
4.0	Over the line CIP surveys and routine monitoring	High levels of AC can affect data obtained especially if AC rejection capability not sufficient on measuring device
5.0	Pigging operations	Need to review risks with ILI vendor possible spark risk when inline inspection vehicle crosses IJ or when scaffolding is erected and if AC voltages can affect PIG data
6.0	AC corrosion	At high AC voltages higher risk of AC corrosion especially when soil resistivity data is not accurately known along whole of pipeline

Assessment of High Risk Locations

- Can actually check AC potentials at CP test posts. This is not always carried out during routine CP checks by some operators
- Should assess pipelines at risk of AC interference and corrosion
- Measurement of AC voltage at CP posts may not identify high risk locations these can be at intermediate locations between CP posts
- Can undertake mathematical modelling to determine touch potential high risk locations from long term interference.

- FIGURE REMOVED

Voltage on Pipeline

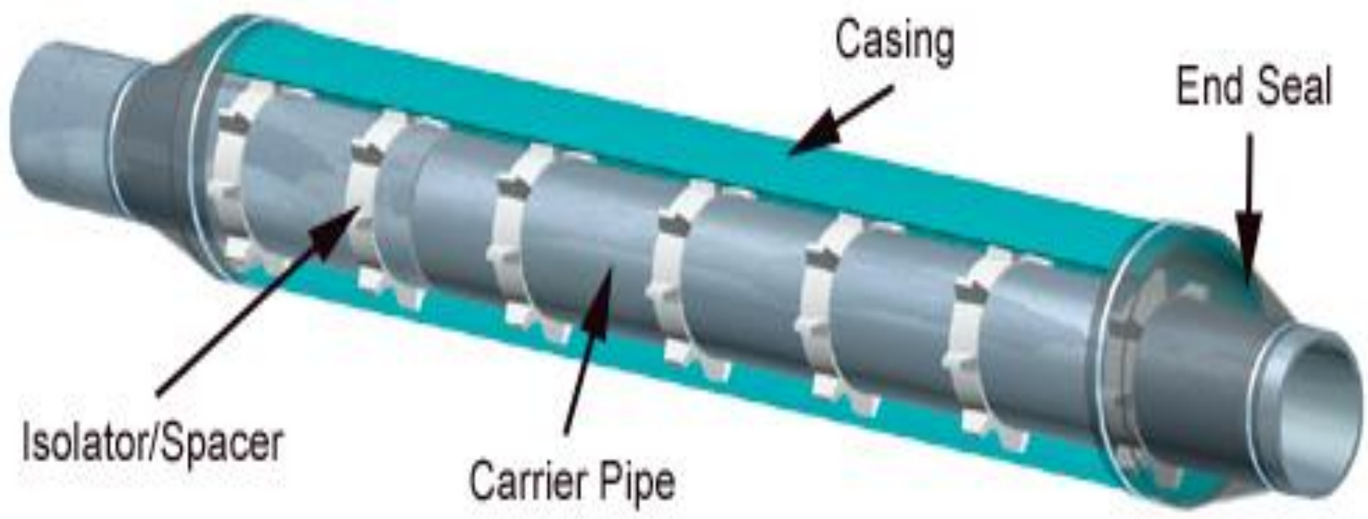
- AC voltage on pipeline will vary based upon load on powerline
- If powerline operator decides to increase load on powerlines e.g. new circuits from offshore windfarms added or new power station constructed then induced AC voltage on affected pipelines will increase.
- This will affect both touch potential and AC corrosion risk
- Pipeline operators need to be aware that situations may change over time and should therefore regularly monitor and assess AC interference levels and risks

Topics for discussion

item	Topic	Comment
1.0	AC spark risk carrier pipelines in casing	There is guidance given in NACE Standard SP0177
2.0	High AC voltage can affect control of CP TR units	Higher AC voltage present on pipeline greater variation in DC current out from CP TR units
3.0	Lightning and arc risk	Risk of damage to pipelines by arcing and also when fires light under powerlines
4.0	AC voltage and ability to perform CIPS and routine CP surveys	High levels of AC can affect data obtained especially if AC rejection capability not sufficient on measuring device
5.0	Where to obtain guidance on construction near powerlines	Detail reference documents will be provided
6.0	Spark risk on testing IJs and current flow in pipelines	AC spark risk certain situations
7.0	Surge protection devices and earthing systems	Current risk and affect of decoupling devices on earthing systems
6.0	Earth faults through groundbeds and AC mitigation earths	Personnel often do not consider that groundbeds can discharge fault current off pipelines

Pipeline In Casing

Pipeline In Sleeve

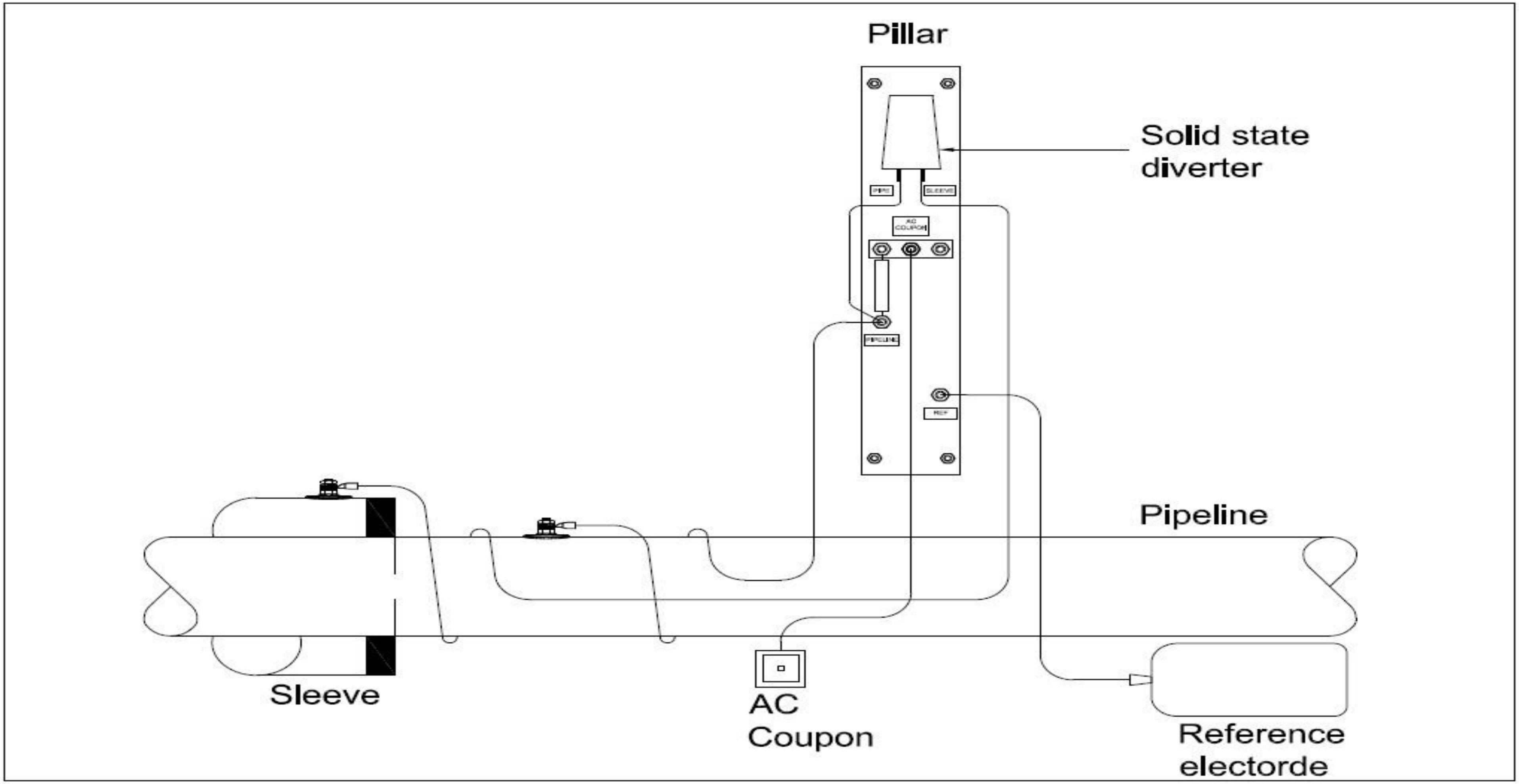


NACE Standard SP 0177 also identifies arc risk on carrier pipeline within sleeve. If carrier pipe exposed to high voltage due to HV or lightning strike there could be an arc within the sleeve as the casing would act as an earth. Use of decoupling devices between sleeve and carrier pipe could be considered to reduce arc risk. Carrier pipes with low wall thickness are at greater risk of damage by arc can also have AC corrosion on carrier pipe within casing

Carrier Pipe in Sleeve

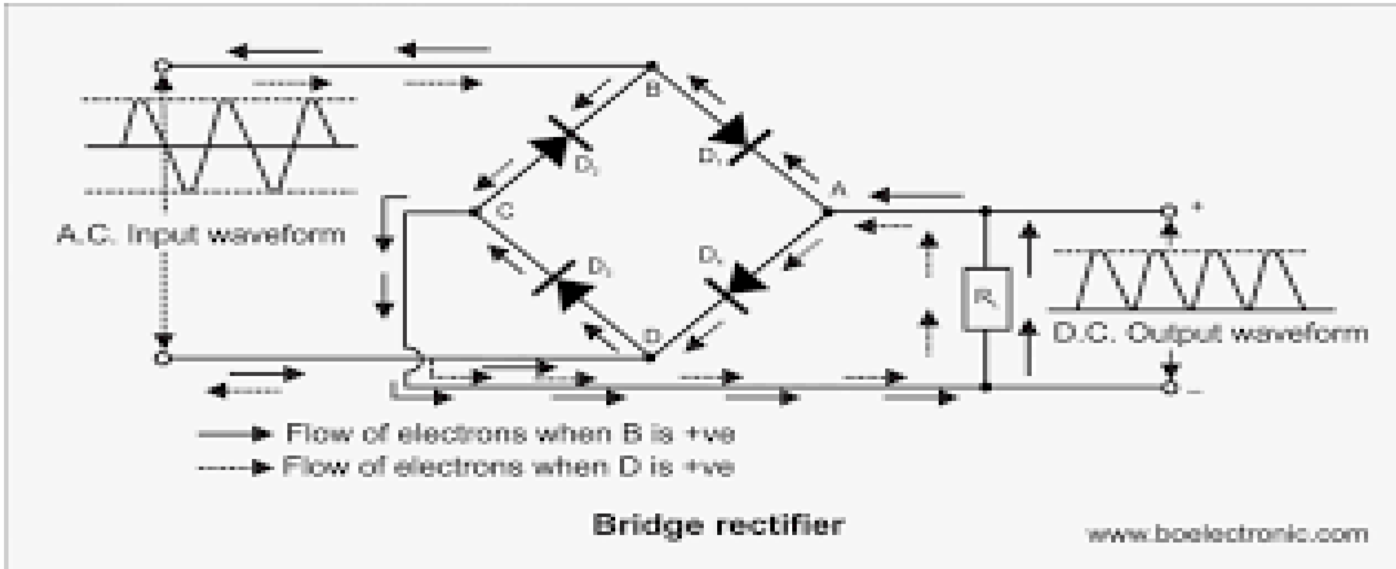
- Carrier pipe if exposed to high voltage could arc to casing.
- Could be perforation of carrier pipe especially if low wall thickness
- Casing if uncoated could be low resistance discharge path for fault current

Prevention of Arcing



Rectification of AC on Pipeline

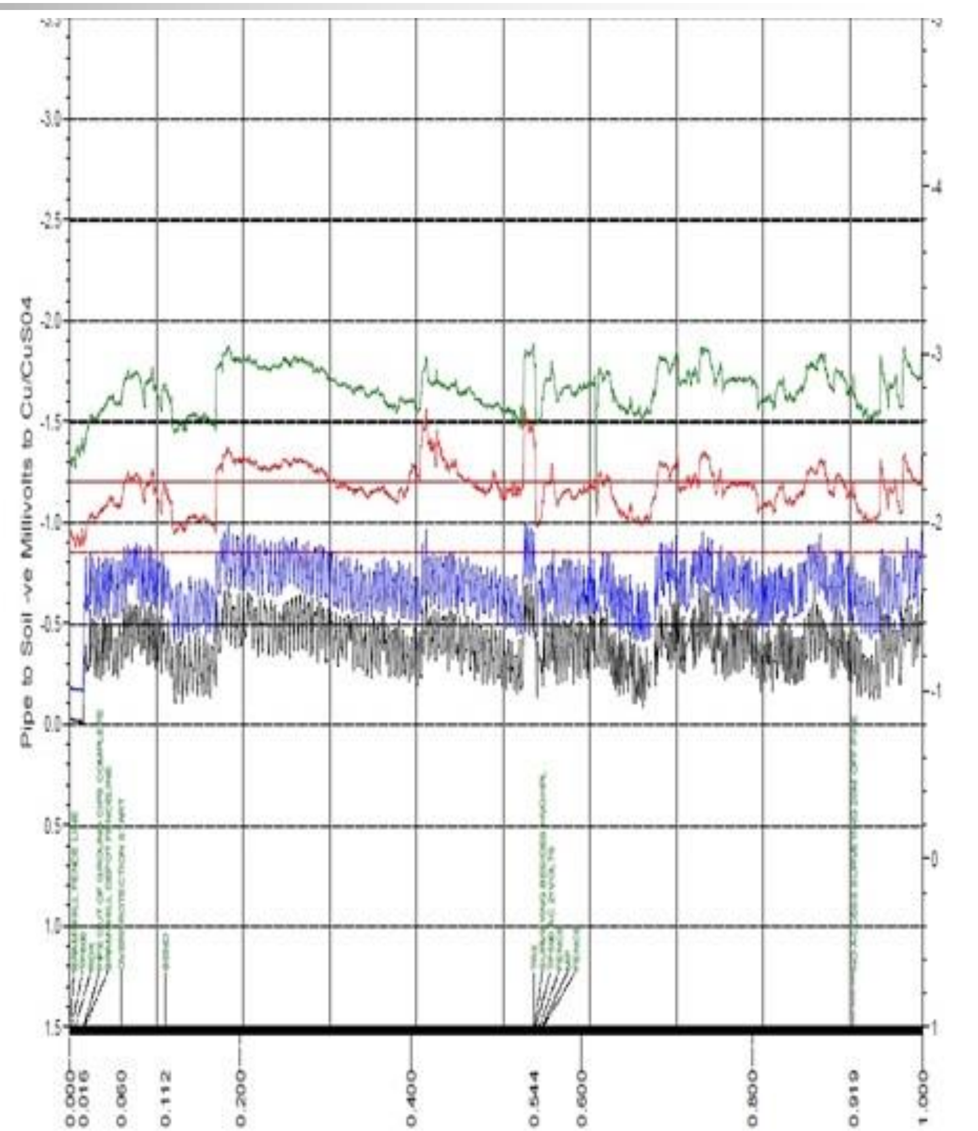
Current Flow Through TR Unit



AC voltage across DC output can be rectified by rectifier bridge to produce DC current . The DC current levels can fluctuate. Use choke in negative and or different TR unit construction

CIP Survey on Pipeline Affected by AC

- The fluctuating CIP plot is due to a fluctuating DC current because the TR unit is rectifying the AC current present on the pipeline.
- It is not actually as a result of DC interference
- This can be seen from the static data logger CIP plot as the AC voltage increases so does pipe to soil potential
- If we permit higher voltages than 15V on pipelines this effect will only get worse i.e it wont be possible to maintain a stable pipe to soil potential



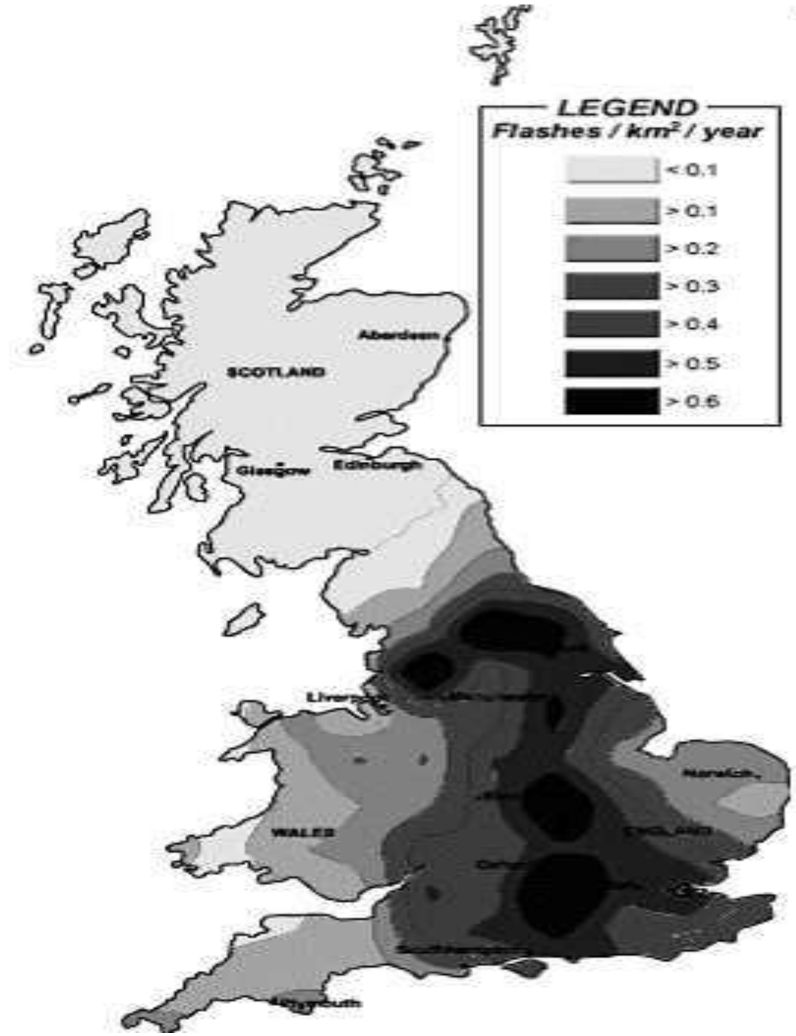
Lightning Risk

Unfavourable Weather Conditions

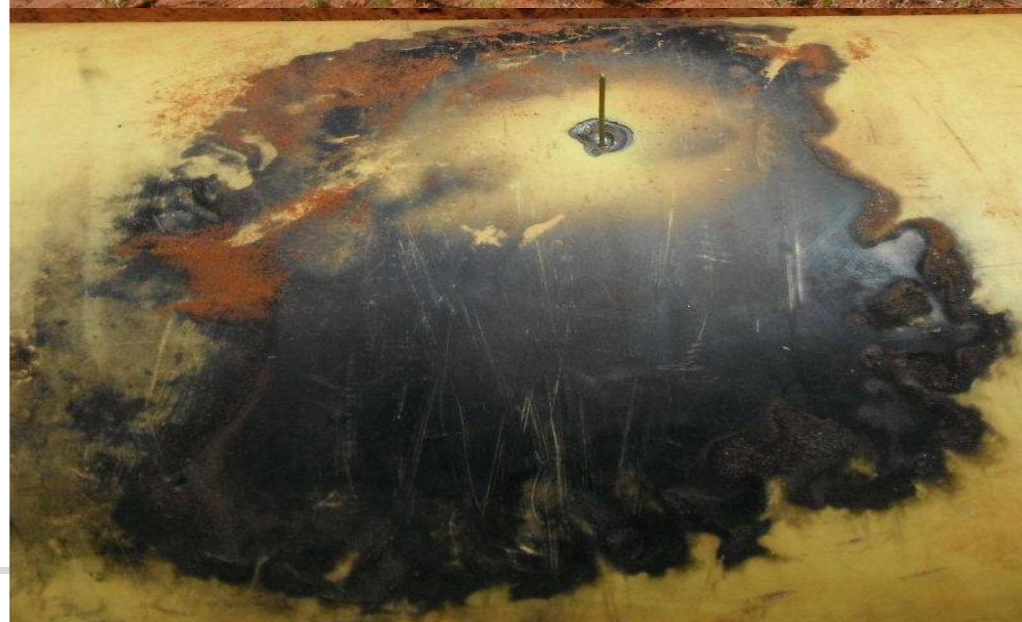
- Lightning strikes and unfavourable weather conditions can initiate fault conditions on a power transmission system. This can cause very high voltages to be induced on the pipeline (1,000's volts).
- Lightning strikes to a pipeline or to earth in the vicinity of a pipeline, can produce effects similar to those caused by ac fault currents.
- Permanent earthing control features may not safely mitigate induced voltages from lightning or from abnormal operating conditions of an overhead power transmission system. Duration of strike is 1 to 2 microseconds with a pause of about 50 microseconds as more charge is accumulated before resuming another strike in a slightly or significantly different direction.
- ***CP testing or work of similar nature should not be undertaken during a period of lightning storm activity or in conditions such as high winds, wet snow or freezing rain, when in the vicinity of power transmission systems. Some International guidance is work with 50 km of lightning storms be suspended***

Lightning Density Map

- Some areas of UK there is a higher risk of lightning than in others.
- Thus, higher risk for personnel working on pipelines
- Lightning density map given in BS EN 62305-2



Lightning Arc Damage to Pipelines



What Caused This to Happen to An 80 Bar Gas Line?

The Investigation

3LPE Coating Internal Epoxy Coating Perforation on Gas Pipeline by Lightning

Spark over voltage

- The spark over voltage for this type of surge protection device is relatively high ≤2.5 kV
- IJs can only withstand 2kV so could be damaged even with surge protector fitted
- Lower sparker over voltage arrestor better surge protection

Safety in Construction Issues

Topic	Comment
Stringing out pipelines close to overhead HV powerlines	Induced voltages can be present on pipelines due to capacitive coupling, welding operations can be affected and personnel safety issues. Contractors need to ensure pipes are effectively earthed at least at two locations .Voltages up to 100V are not uncommon
Plant crossing of powerlines	If construction plant cross powerlines GS 6 notification in place but all ENA guidelines to be followed e.g. ENA TS-43-8 gives guidance on clearance distances for different voltage cables
Cutting of pipelines	If pipelines are cut then there could be an incendive spark risk on separating of pipelines either AC or DC current flow in cross country pipelines will exist and could be 10s of Amps of AC
AC voltages present across IJs	If an IJ is unintentionally short circuited this could create a spark risk if AC voltage exists across an IJ. Sometimes testing IJs can result in incendive ignition risks. Particular care required during pigging operations
Personnel working on pipelines close to powerlines	Need to be aware of electrical risks and also safe working distances. Correct PPE and test equipment complying with GS 38
Work on CP groundbeds	This is a risk not often thought of. However, CP groundbeds will act as earths for discharge of AC faults on powerlines. Current will discharge through TR units to the groundbed. Personnel working on a groundbed replacement could receive a fatal electrical shock risk. Need to disconnect groundbed cables at TR unit before work takes place on groundbed installation.

Safety in Construction Issues 1

Topic	Comment
Cranes and side booms	Rubber tyre vehicles should be fitted with earth chains when operating underneath or close to overhead power line
Static shock risk particularly on 3LPE systems	On 3LPE system Holiday detection of coating can leave static charge present personnel contacting coating pipe could receive shock not likely to be fatal due to current but could result in involuntary action and accident. Risk greater with 3LPE coatings than FBE.
AGI Touch Voltage tolerance	Use of crushed stone or similar high resistivity material to be used within AGI will increase touch voltage resistance for personnel
Overhead/buried power cables	Should ensure that all cables whether overhead or buried are located within working width and the nature of the voltage hazard is identified
Health of workers	Personnel with heart conditions who may be more susceptible to electric shock to avoid work on pipelines where hazardous touch voltages may be present
Welding	AC voltages present on pipeline can affect welding operations

Holiday Detection of Pipeline Coating

3 Layer Polyethylene

Safety in Operation Issues

Topic	Comment
Pipelines close to overhead HV powerlines	Induced voltages can be present on pipelines due to low frequency Inductive coupling. Voltages up to 100V could exist in some locations and personnel need to be aware of this risk
Transformer rectifiers	Transformer rectifiers ideally should have double wound isolating transformer to prevent AC mains voltage flowing to pipeline during fault. Also reduced level of AC ripple on high output current TR units. When working on TR it is effectively connected to pipeline so can form part of pipeline in terms of electrical hazard.
Short circuit of IJs/IFs	Not uncommon to have resistive connection across IJ/IF e.g cladding or metallic paint coating. During voltage surges these can burn out and provide incendive ignition risks
AC voltages present across IJs	If an IJ/IF is unintentionally short circuited this could create a spark risk if an AC voltage exists across an IJ i.e. each side of IJ. Coating of IJs/IFs prevents fortuitous short circuit e.g. dropping of tools across IF. Erecting scaffolding for pigging operations possible short circuit risk

Safety in Operation Issues 1

Topic	Comment
Training	Need to be ensure operatives aware of electrical risks and also safe working practices
Lightning electrical storm activity	Need to limit work during these times as higher probability of shock. 3m touch potential separation limit for different earth systems e.g separation of fence from pipework by 3m partially associated with increased shock risk from lightning activity.
Where PCRs are installed	Limits ability to perform CIP and DCVG surveys but can also cause AC current to flow in earth cables and pipework. If disconnecting PCR cables. Earthing arrangement not strictly TN-S as AC current will flow in earthing cables.
Change of situation	If new power systems installed at substations or power stations then the Ground Potential Rise can change and Ground Potential Rise levels could change and affect touch potential risks on pipeline resulting in higher levels. Increase in fault current will increase ground potential risk. Induced voltage levels can also increase if power loading on powerlines are increased
Pigging operations	Effect of AC interference on pigging operations should be considered possible spark risk on erecting of scaffolding, inspection vehicle shorting IJ and AC affecting pig data

Safety in Operation Issues 2

Topic	Comment
Electrification of Rail Lines	If rail lines are electrified how this affects a pipeline should be assessed especially if pipeline runs parallel with traction circuits. Special considerations should be undertaken e.g. location of pylons, spacing of CP test
PCRs, surge protection and earthing	Need to ensure electrical engineers review and accept use of decoupling devices and surge protection
Microwave transmission	Should not install microwave transmission towers in close proximity to AGIs guidance given in PD/CLC TR 50427 Assessment of inadvertent ignition of flammable atmospheres by radio-frequency radiation. Guide
Surge protection inspection	To comply with BS EN 60079-17 Explosive atmospheres Part 17: Electrical installations inspection and maintenance in case of surge protection devices it is visual annual and every 3 years detailed
Use of decoupling devices and over the line surveys	PCRs store energy and where decoupling devices are installed they can affect the ability to carry out over the line surveys e.g. CIPS and DCVG.

NACE SP 0177 Topics

Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems	
Topic	Comment
Power Arc Overhead Powerline to Pipeline	If the potential gradient in the earth is large enough to ionize the soil for a finite distance, a direct arc from the power system ground to the structure can occur within that distance and result in coating damage, arc burn, or puncture/failure of the structure.
Casings	Bare or poorly coated casings may be deliberately connected to a coated structure through a DC decoupling device to lower the impedance of the structure to earth during surge conditions and to avoid arcing between the structure and the casing.
Guidance on conductor size	Bonding cables and current carrying cables should be of sufficient conductors size to carry the likely fault current for duration of any fault.
Guidance on body resistances and permissible currents	The NACE standard provides guidance on safe current and body resistance levels . These values are lower than given in EN standards

NACE SP 0177 Topics

Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems

Topic	Comment
Safe voltage levels	I/Js max voltage 2kV, 2 kV for tape wraps and coal tar enamels and 3 to 5 kV for fusion-bonded epoxy (FBE) and polyethylene coatings for a short duration
Attachment of grounding cable	The grounding cable shall first be attached to the grounding facilities and then securely attached to the affected structure. Removal shall be in reverse order. Properly insulated tools or electrical safety gloves shall also be used to minimize the shock hazards. THE END CONNECTED TO THE GROUND SHALL BE REMOVED LAST
Above ground connections	At all aboveground pipeline metallic appurtenances, devices used to keep the general public or livestock from coming into direct contact with the structure shall be examined for effectiveness. If the devices are found to be ineffective, they shall be replaced or repaired immediately
CP test lead connection	In making test connections for electrical measurements, all test leads, clips, and terminals must be properly insulated. Leads shall be connected to the test instruments before making connections to the structure. When each test is completed, the connections shall be removed from the structure before removing the lead connection from the instrument. All test

Clearance Distances

Work Underneath Powerlines

- Need to follow guidelines given in GS 6 for work underneath powerlines
- Erect warning tape and notify powerline operator of work underneath powerlines comply with ENA TS 43-8 guidelines
- The latter document gives guidance on clearances between plant and powerlines and also how far away safety barrier need to be erected from powerlines

ENA TS 43-8 Guidelines

Description of Clearance	Nominal System Voltage (kV) Minimum Clearance Distance m				
	<33	66	132	275	400
Line Conductor to any Point Not Over a Road	5.2	6.0	6.7	7.0	7.6
Line Conductor to Road	5.8	6.0	6.7	7.4	8.1
Line Conductor to Any Object on which a Person Cannot Stand	0.8	1.0	1.4	2.4	3.1

Clearance Distances ENA TS 43-8

Table 11.2 - Vertical Passing Clearances

Item No.	Nominal System Voltage		≤33 kV	66 kV	132 kV	275 kV	400 kV
11.2.1	Passing Clearance fixed height loads	m	0.8	1.0	1.4	2.4	3.1
11.2.2	Passing Clearance variable height loads	m	2.3	2.5	3.2	4.1	5.0

The above clearances shall be used to determine the maximum distance to the underside of barriers erected to prevent vehicles or plant from infringing these clearances whilst traversing the line. The height to the underside of the barrier shall be the minimum ground clearance of the line less the specified passing clearance in Table 11.2.

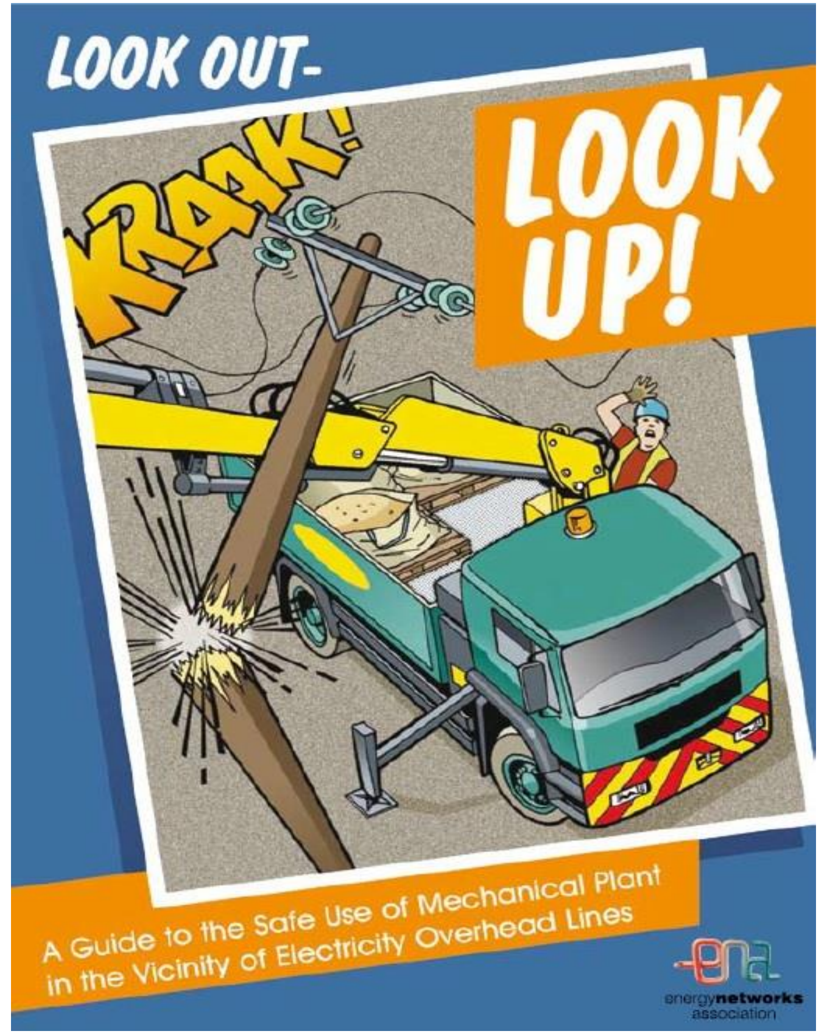
Table 11.1 - Horizontal Distances to Safety Barriers

Voltage / Type	≤33 kV Wood Pole	66 kV Wood Pole	132 kV Wood Pole	132 kV Tower	275 kV Tower	400 kV Tower
Minimum horizontal distances to safety barriers.	6.0 m	6.0 m	6.0 m	9.0 m	12.0 m	14.0 m

Note: Site conditions will dictate whether this clearance is adequate and consideration shall be given to line parameters e.g. span length, maximum sag etc. when calculating an actual clearance.

ENA Guidance

- ENA gives good guidance on measures to take for work near powerlines
- HSE document GS 6 statutory guidelines for work near overhead pylons



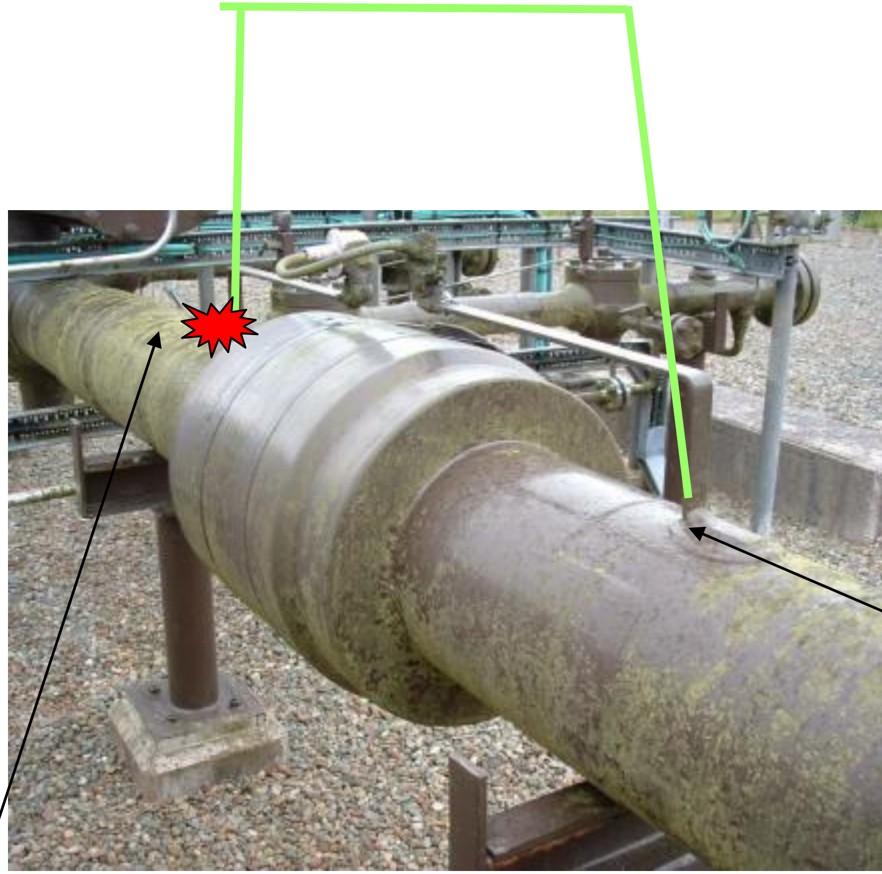
Testing IJs and IFs

Flange Testers

- The internal resistance of these devices is only a few ohms
- If there is an AC voltage present across a flange then there may be a spark risk on testing
- We have seen this on testing a flange with sparks on making contact with probes
- Currents above a few mA flow and can create a spark dependent upon voltage

Short Circuit of IJ

Can get short circuit from pig scaffolding, testing with CP equipment and tools shorting flange /I/F



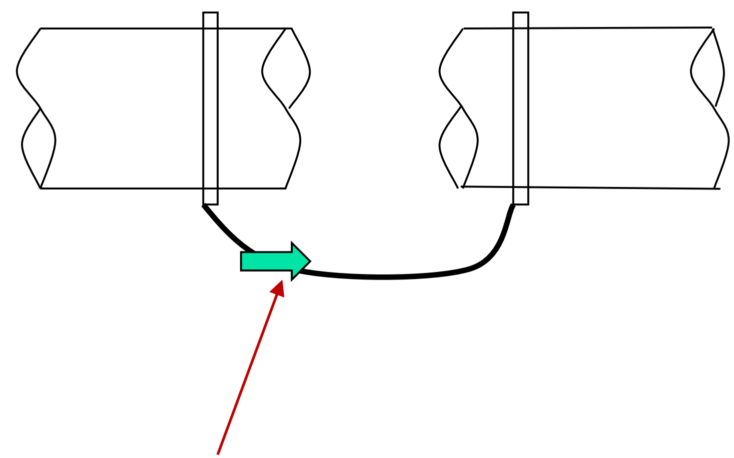
15V AC pipeline line of I/J

0V AV Dead side of I/F

Current Flow in Pipelines

Disconnection of Piping

- Cathodically protected and in some cases non cathodically protected pipes will have AC/DC current flowing in the pipe wall. If the pipes are mechanically disconnected, the current flow will be disrupted which could cause sparking.
- An alternative path should therefore be provided for the current when disconnecting any pipework by installing an electrical continuity bond across the intended break. The continuity bond should be left in place until the pipe is reconnected.
- In addition it is some times advisable to temporarily switch off any transformer-rectifiers affecting the section of pipe being worked on at least 24 hours in advance.



Current flowing in bond

Cause of Incident

- It was later determined the rectifier protecting the piping was on and not locked out at the time of the incident. A cathodic protection cable was found attached to the piping being removed.
- Workers did not recognize the cable attached to the pipe as a potential energy source and did not take action to isolate out all sources of energy.
- Bonding cable design was inadequate to provide continuous bond during a pipe jump. Workers did not consider the potential for pipe movement to defeat the magnetic strength of the bonding cable.
- Flammable product in dead leg was not adequately drained to prevent fire potential.

PCRs and Surge Protection

Use of PCRs Across IJs

- Not all operators use these devices
- For operators that don't have PCRs there is a possible AC spark risk across IJ. There can be a different AC voltage each side of IJ and if the IJ was short circuited there may be a spark/incendive ignition risk
- Those operators that do have PCRs fitted can have appreciable AC current flow through any PCR. Thus, there is a possible spark risk on disconnection of AGI pipework or PCR cables. There will be AC current flow in the AGI earthing so disconnection of earth cables could result in spark risk. AGI earth is also not strictly a TT or TN-S earthing system now.

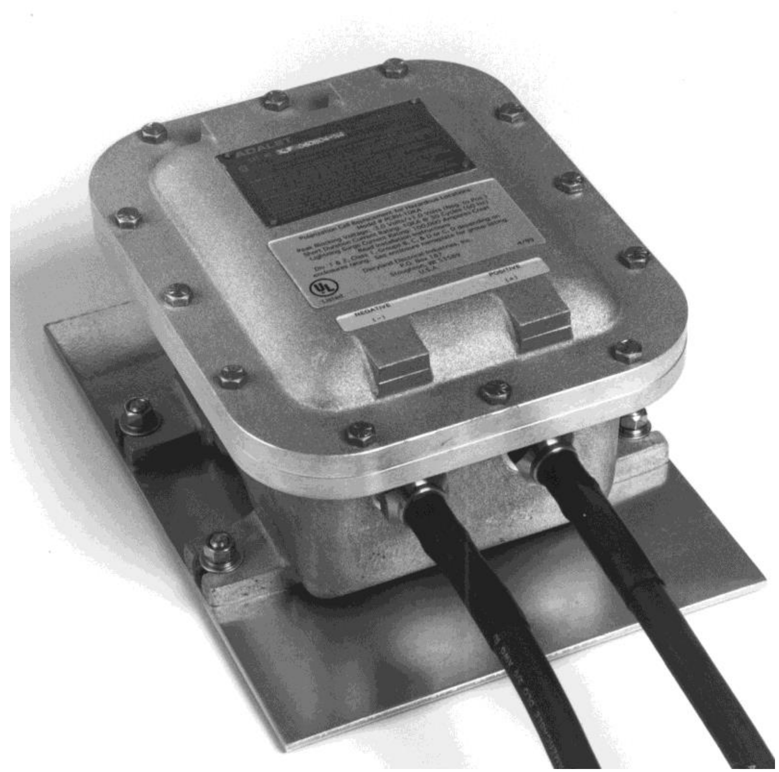
PCR Across Flanges or IJ

- The term PCR stands for Polarization Cell Replacement. A PCR is a solid-state device designed to simultaneously provide DC decoupling and AC continuity / grounding when used with cathodically protected structures, such as pipelines
- PCRs have very high AC fault current and lightning surge current ratings.
- Low impedance about 0.05 Ohms and allow AC currents up to 40A to flow to earth but block low level DC voltages typically + 2V to -2V.
- PCRs ensure effective AC coupling across flanges/IJs but there safety issues to consider:
  - Spark hazard on disconnection of cables
  - Quite easy to short terminals as Zone 2 PCR terminals do not have a protective covers
  - There will be AC current flowing in pipework AGI side of I/IJ could be spark hazard on disconnection.
  - Will cause AC current to flow in AGI earth
  - If AGI fence connected to AGI earth then any voltage fault on pipeline will be transferred to the fence

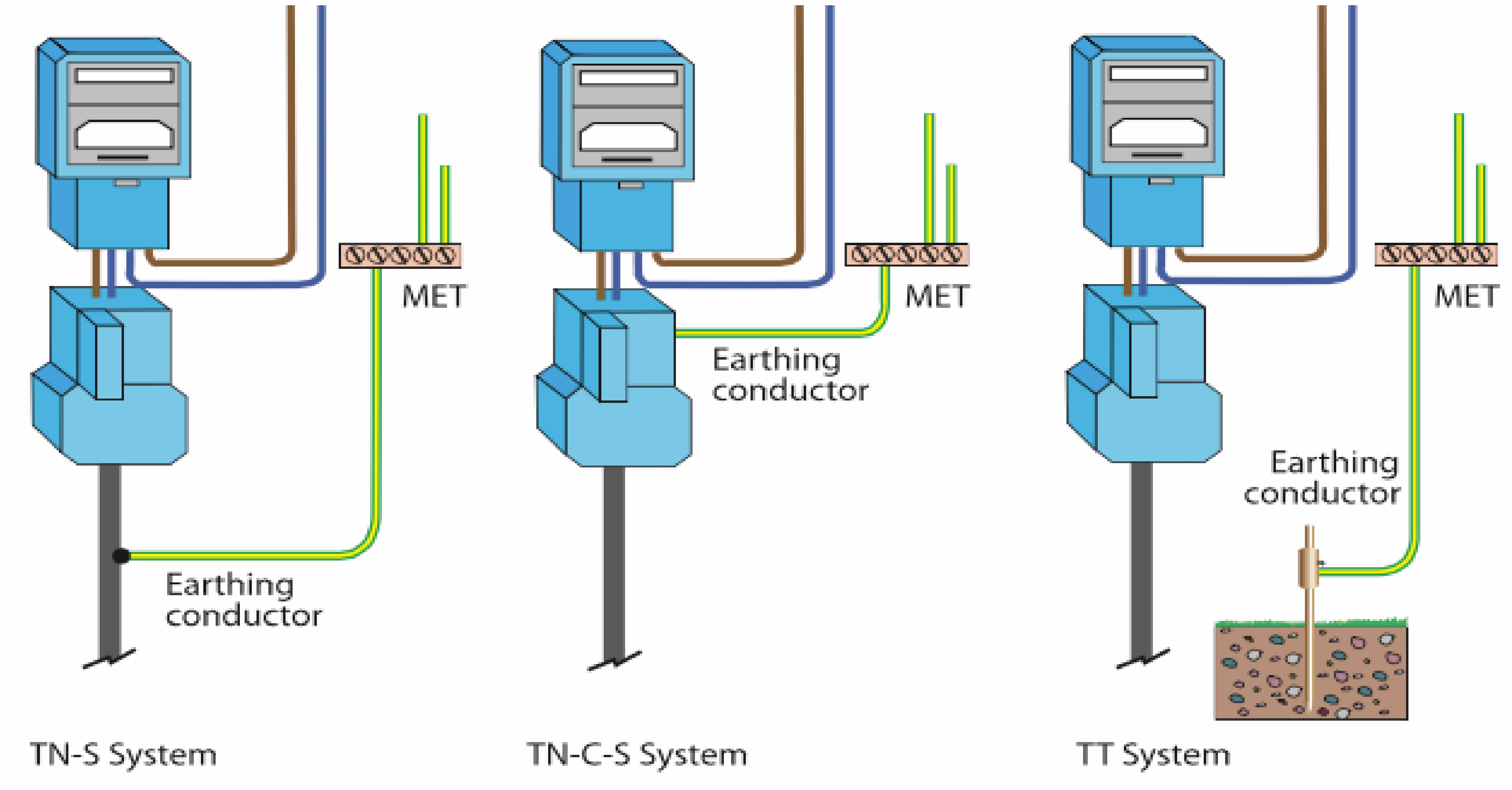
PCRs for Zone 2 Area Easy to Short Circuit

Zone 2 Certified Device- Spark risk easy to short circuit terminals

Zone 1 Certified Device Terminals within EExd enclosure



Earthing Connections



TT and TN-S With PCR

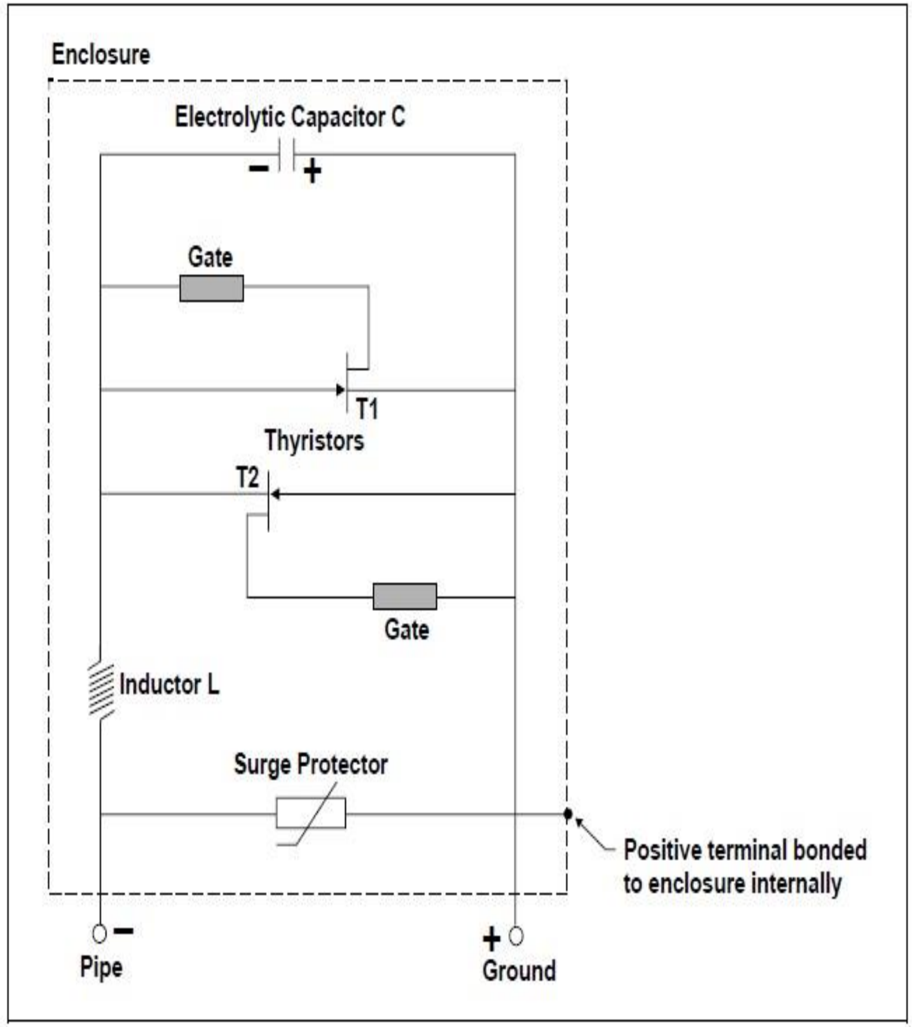
- Earthing systems in hazardous areas are either a TT or TN-S system. Terra is Latin for Earth and the TN –S means earth and neutral are separate. TT means the protective earth connection for the consumer is provided by a local earth electrode, and there is another independently installed at the generator. There is no 'earth wire' between the two
- These system are installed in hazardous areas for safety reasons as when other electrical earthing systems e.g Protective Multiple Earthing (PME) are employed disconnection of earth cables or earthed structure can result in a spark risk because of neutral current flow in earth cables.
- When PCR connected across IJ/IF then AC current flowing in pipeline can flow through AGI earth system. This current level can be quite substantial sometimes up to 40A and result in spark risk on disconnection of PCR cables, earth cables or pipework in a similar manner to that with a PME system. Electrical engineers need to be aware of this risk as CP designers do not often have sufficient understanding of the nature of different earthing systems

Surge Protection Issues

Topic	Advantage	Disadvantage
Protection of IJ from damage max voltage limit for IJs is 2000V	Surge protection helps protect IJ from overvoltage. Failed IJs very difficult and expensive to repair	Fault current discharged to AGI earth if AGI earth low resistance this could cause voltage rise above safe limits and damage sensitive equipment
AC coupling	PCR is used this will ensure pipeline and AGI pipework electrically connected in AC terms. Thus, no AC touch or spark risk across IJ. If spark gap device then no AC coupling	AC current induced on pipeline will also flow through AGI pipework and earth if PCR installed. If fence is bonded to AGI earth then fault on pipeline will be transferred to fence
IFs protected by surge arrestors	If PCR and surge protection device correctly rated can prevent spark across IF under fault conditions	Need to ensure correct Ex rating for arrestor some are only EExn certified so only Zone 2 use. Surge arrestors and PCRs can be easily short circuited and give spark risk

PCRs in Earthing Circuits

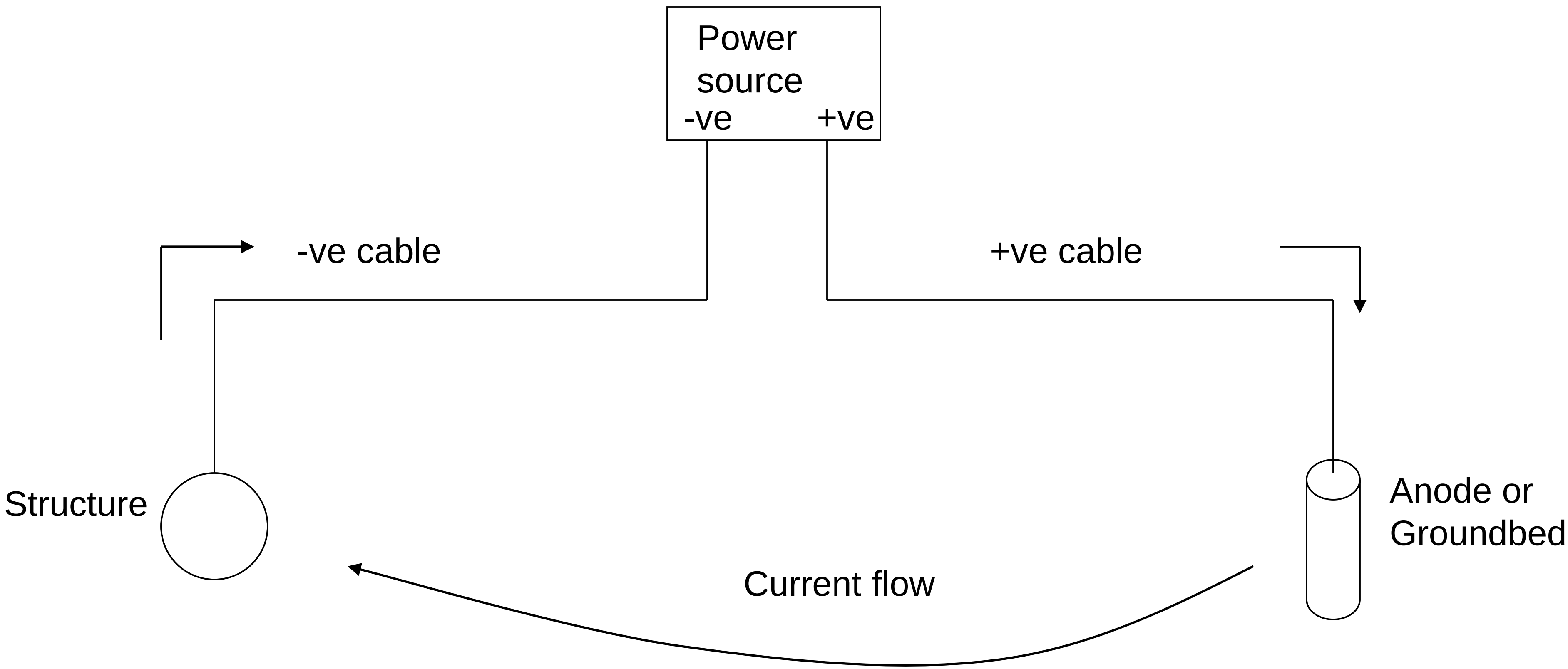
- Some operators put PCRs in earthing circuits to DC electrically isolate earths from pipeline but allow AC current to flow to earth
- Other operators do not permit the use of PCRs for this application as BS 7671 does not permit switching devices in earthing circuits
- Always seek approval of discipline electrical engineer before installation of surge protection



Arrestor on left Zone 1 one on right only Zone 2

Groundbed Installation

Basic Features of an Impressed Current CP System

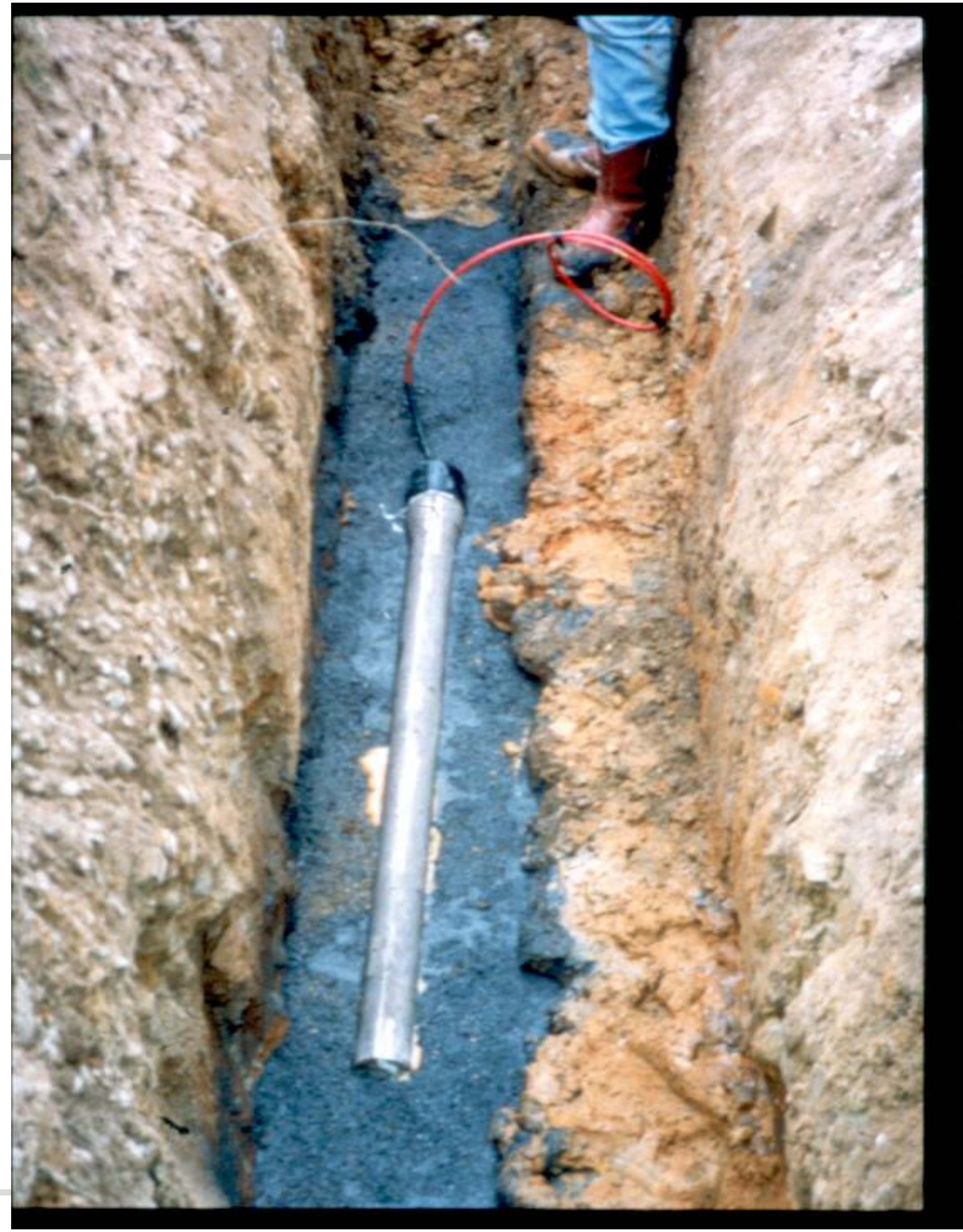


Work on Groundbed or TR

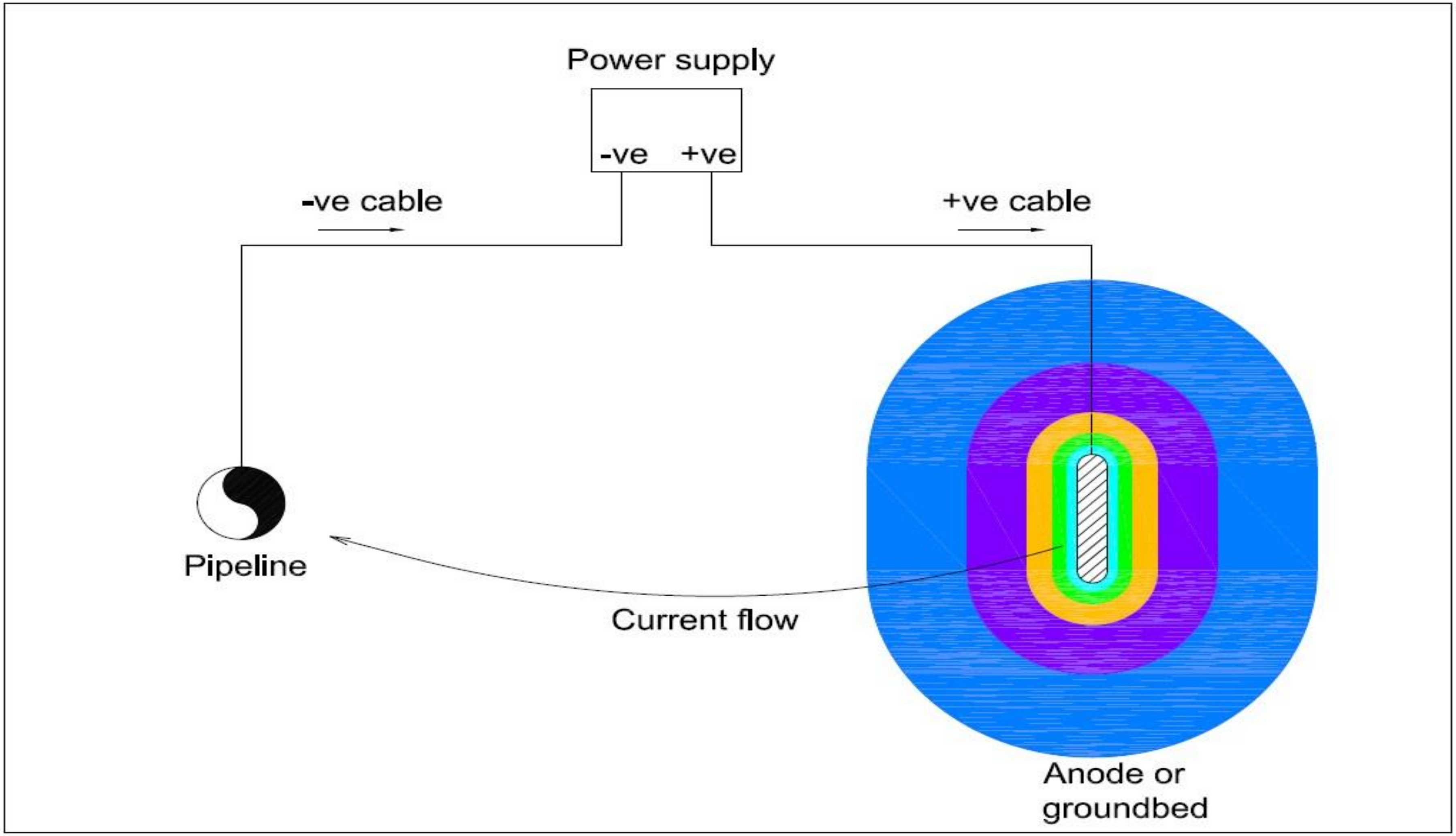
- Groundbeds typical resistance values 2 to 10 ohms will act as a good earth to discharge fault current off pipelines.
- The ground potential may rise at a groundbed and close to it during fault conditions as the current may flow through the CP TR unit to the groundbed or a surge diverter on the TR will discharge the current to earth .
- If personnel were working on a groundbed installation they could be exposed to a possibly fatal shock risk. It would be totally unexpected as it would be nowhere near a HV source.
- Disconnect groundbed cable at TR unit or pipe connection to TR to mitigate the risk when constructing or replacing groundbeds. It is simple but effective !
- Similar steps apply when installing earths associated with AC mitigation systems connect earth to pipeline only at the last minute after earth has been installed.

Groundbed Construction

- Groundbed act as earths on pipelines and current can discharge to earth at groundbeds during fault conditions
- Anyone working on groundbed at time of fault would be exposed to the risk.
- There would be a touch potential and step potential risk
- Workers could be exposed to the risk for the entire period of groundbed construction
- Risk would only be present if DC positive cable connected to TR unit at time works take place.
- Precaution is to disconnected either DC positive or DC negative connection from TR unit before any work on groundbed takes place



Voltage Rise Near Groundbed



Training

Training and Awareness

- My experience is that in general there is not the awareness that there should be within the pipeline industry on electrical safety risks associated with work on pipelines.
- Pipelines are still routed close to powerlines and pylons by designers
- A lot of technicians would not know what a touch potential was?
- Pipeline design codes e.g TD 1 and BS PD 8010 give limited guidance on electrical safety risks and concentrate more on AC corrosion risk
- New substations installed close to pipelines without assessment of touch potential risks
- Designers, planners all need to be aware of electrical interference risks and the risk should be identified in both Construction and Design Risk Registers
- BS EN 50443 recommends that *the voltage to earth of the pipeline and the voltage difference on the insulating joints shall be evaluated in normal operation and in fault conditions*

Training and Awareness-Cont

- Pipeline operators need to ensure that all personnel who could come in contact with a pipeline are aware of the possible electrical safety risks and dangers.
- There have not been any known incidents of fatal electrical shocks as HV powerline faults are a rare event say once every 10 years.
- BS EN 50522 states typical probability of an earth fault occurring, which results in a significant earth potential at a transmission substation, is 0.2 per annum; i.e. one significant earth fault every five years on average.
- If personnel experience electrical shocks when working on a pipeline they should be advised to report this
- Lightning strikes are a more frequent occurrence
- About 80% of powerline faults are related to spurious trips caused by lightning or bird strikes.

Mitigation measures

- Wear insulated footwear and do not kneel on ground when taking CP readings.
- Treat test post studs as possibly live
- Carry out pre-work risk assessments
- Use insulating gloves where possible and knee pads.
- Use fused test leads complying with HSE guidance note GS 38 on test equipment.
- Check the surrounding environment before carrying out testing to ensure that in the event of shock any slip or fall would not cause damage.
- Limit time making contact with CP posts

Powerline Operators

- Powerline operators increase load on powerlines without advising pipeline operators. This is because at present they believe they have no requirement to do so.
- Cable operators often do not consider the effects that overhead powerlines will have on buried utilities.
- There needs to be greater awareness in the power generation industry especially at the planning stage of the effects of AC interference on utilities.
- There is a general lack of awareness in the power generation industry of the effects of AC interference on buried utilities

Summary of Issues

Topic	Advantage
Touch potential	Is there sufficient separation between pylon /substation and pipeline to ensure touch potential within safe limits ? Have risk touch potential locations along existing pipelines been identified. Need clarity on permissible voltages and they should be as low as possible
Training	Have operatives been given training in awareness of AC interference risks ? Also designers need to be given guidance on risks as well as pipeline design standards give limited information at present in terms of electrical safety
UKOPA GPG	We will try and identify a lot issues raised in this presentation in the guide in relation to AC interference
Awareness	Need to be aware of fact that there issues associated with installation of microwave towers close to AGIs and overhead pipeline crossings of electrified railways. If railways electrified then this can affect overhead pipe crossings or result in AC interference on pipelines that are routed parallel to rail lines. If powerlines being up rated this can affect AC voltages levels on existing pipelines

What the Pipeline Industry needs to Consider

Topic	Advantage
Power cable operators	If there are new developments e.g power stations, substations for offshore wind to be installed. The effects on buried services from increased loads on power cables needs to be considered at an early stage. At present power cable operators do not advise pipeline operators of any new developments
Touch voltage limits	There should be clarity as to acceptable touch voltage limits for pipelines. These values should also take into account access by not electrically instructed personnel, the general public and operation and control of pipeline CP systems
Assessment of High Risk Locations	Operators should identify high risk locations in terms of electrical shock risk to personnel
Standards	Pipeline design standards need to address not only AC corrosion risk but electrical safety risk from AC interference

Relevant Standards for AC Interference On Pipelines

Document	Title
AS/NZS 4853	Electrical hazards on metallic pipelines
BS EN 15280:2013	Evaluation of a.c. corrosion likelihood of buried pipelines applicable to cathodically protected pipelines
BS EN 50122-1:2011+A4:2017	Railway applications. Fixed installations. Electrical safety, earthing and the return circuit. Protective provisions against electric shock
BS EN 50443:2011	Effects of electromagnetic interference on pipelines caused by high voltage a.c. electric traction systems and/or high voltage a.c. power supply systems
BS EN 50522	Earthing of power installations exceeding 1 kV a.c.
BS EN 61010-1:2010	Safety requirements for electrical equipment for measurement, control, and laboratory use. General requirements
BS EN ISO 15589-1:2015	Petroleum, petrochemical and natural gas industries. Cathodic protection of pipeline systems. On-land pipelines
BS EN ISO 18086:2017	Corrosion of metals and alloys. Determination of AC corrosion. Protection criteria
ENA TS 41-24	Substation Earthing
ENA TS-43-8 Issue 3 -	Overhead Line Clearances
GS 6	Avoiding danger from overhead power lines
PD IEC/TR 60479-1	Effects of current on human beings and livestock- General Aspects
NACE SP0177-2014	Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems

THE END

Questions ?

UKOPA
United Kingdom Onshore Pipeline Operators' Association

UKOPA Good Practice Guide

AC Corrosion Guidelines

UKOPA/GPG/027

October 2019

GUIDANCE ISSUED BY UKOPA:

The guidance in this document represents what is considered by UKOPA to represent current UK pipeline industry good practice within the defined scope of the document. All requirements should be considered guidance and should not be considered obligatory against the judgement of the Pipeline Owner/Operator. Where new and better techniques are developed and proved, they should be adopted without waiting for modifications to the guidance in this document.

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Disclaimer

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1. EXECUTIVE SUMMARY

This Good Practice Guide (GPG) is intended to provide guidance to pipeline operators on the management of alternating current (a.c.) interference on pipelines with specific emphasis on a.c. corrosion risk. It is intended to clarify and expand upon the information originally provided in BS EN 15280 [1], which has now been withdrawn and has been replaced by BS EN ISO 18086 [2]. The electrical safety related issues on pipelines from a.c. interference is detailed in BS EN 50443 [3] and additional guidance is provided in UKOPA/TBN/005 [4].

This GPG gives information to pipeline operators on applicable standards and published literature. It also provides guidance on how to mitigate the a.c. corrosion risks on pipelines from interference caused by overhead and buried power cable systems or a.c. traction systems. The interference may occur as a result of either inductive, capacitive or resistive coupling.

The information that pipeline and power line system operators generally require to assess the levels of interference when new or existing powerline systems or power stations are installed within the vicinity of pipelines is identified in Appendices C, D and E in this GPG.

This GPG does not discuss the d.c. stray current interference risks on pipelines. Guidance on d.c. interference is given in BS EN 50162 [5], which will be replaced in the near future by ISO 21857 [6].

This GPG provides information on the management of the a.c. corrosion risk on existing pipeline systems and guidance on the a.c. interference considerations for new pipelines. A.C. corrosion can occur in certain circumstances and if the a.c. interference risk is not managed. It can result in high rates of corrosion on cathodically protected pipelines affecting pipeline integrity even if the CP levels comply with published criteria.

The GPG provides guidance on the design of a.c. interference mitigation and monitoring systems and the measures that pipeline operators should consider on existing pipelines and during the design of new pipelines or diverted pipeline systems in relation to a.c. interference.

Information on the maintenance procedures that should be followed and the nature and frequency of the tests that should be conducted on pipelines susceptible to a.c. interference to ensure that they are effectively protected from an enhanced corrosion risk due to a.c. interference is also provided.

2. INTRODUCTION

2.1 Background

This document has been prepared to provide pipeline operators with guidance on the control and management of the a.c. interference risks on buried and above ground pipelines, which can result in a.c. corrosion. The requirements in relation to evaluation of a.c. interference and corrosion risks on buried pipelines and the protection criteria to mitigate a.c. corrosion risks are defined in BS EN ISO 18086. The latter standard provides guidance on protection criteria and methods to mitigate and evaluate a.c. corrosion risk but does not provide detailed guidance on all aspects of a.c. interference. The latest international guidance on a.c. corrosion on buried pipelines is provided in National Association of Corrosion Engineers (NACE) SP 21424 [7]

The safety aspects of a.c. interference from a.c. power lines and traction systems on pipelines are detailed in BS EN 50443 and are now supplemented by the guidance given in UKOPA/TBN/005. It should be noted that UKOPA/TBN/005 is only available to UKOPA Members.

This document is intended to provide information to pipeline operators, designers and other relevant organisations on the requirements to minimize and manage the risk of a.c. corrosion on buried metallic pipelines. It is also intended to provide guidance on the operation and maintenance of pipelines that are at risk of a.c. interference and expand upon the information provided in existing standards.

2.2 Scope

The guidance in this document is applicable to all buried steel pipelines operated by UKOPA members and provides information on good practice for construction and maintenance.

It includes the risks from both 50 Hz overhead and buried power cables and a.c. traction systems.

This GPG provides information on the design of a.c. interference monitoring and mitigation systems on new and existing pipeline systems. It addresses the operational and maintenance requirements for pipelines susceptible to a.c. interference to mitigate the a.c. corrosion risk.

2.3 Application

The document is considered by UKOPA to represent current UK pipeline industry good practice within the defined scope of the document. All requirements should be considered to be guidance and should not be considered to be obligatory against the judgement of the pipeline Owner/Operator. Where new and better techniques are developed, they should be adopted without waiting for modifications to the guidance in this document.

Within this document: **Shall:** indicates a mandatory requirement

Should: indicates good practice and is the preferred option

3. AC INTERFERENCE

3.1 General

A.C. interference on new and existing pipeline systems from crossing or parallelisms with overhead or buried power lines is a serious concern. There are two main issues associated with this phenomenon.

The electrical safety risk to pipeline personnel, sub-contractors working on a pipeline system and the general public, that arises if any contact is made to a pipeline or its above ground appurtenances, which include CP test cables, at the time that there are short term or also long-term a.c. voltages present. The electrical safety risks in relation to pipelines during both operation and construction are discussed in detail in BS EN 50443 and UKOPA/TBN/005 Electrical hazards on pipelines.

The a.c. corrosion risk on buried pipelines, which is a phenomenon that has been identified on cathodically protected pipelines throughout the world. Problems arise where there are alternating currents, above defined limits, present on a pipeline; even if the cathodic protection levels are satisfactory and meet the criteria defined in BS EN 12954 [8], there can still be ongoing corrosion. The UK experience in relation to a.c. corrosion on pipelines is summarised in Appendix E.

The a.c. corrosion criteria given in BS EN ISO 18086 have primarily been based upon laboratory studies and field measurements conducted in mainland Europe. Guidance on a.c. corrosion protection criteria is given in section 4. A certain element of caution should be exercised when interpreting data using different criteria identified in BS EN ISO 18086. Indeed, all that can be stated is that a pipeline is at risk of a.c. corrosion based upon the criteria stated, but not the rate of corrosion unless corrosion rate monitoring probes are installed. In line inspection data can provide information on the rate of defect growth and may also be used to assess rates of a.c. corrosion. There are however limitations with the ILI technique in evaluating possible a.c. corrosion features and these are discussed in section 6.15.

3.2 Coupling between Pipelines and AC Power Sources

There are three different methods of coupling between a.c. power lines and pipelines that can result in a.c. corrosion:

Low frequency induction (LFI) arises due to the inductive coupling between long structures, e.g. between pipelines and power lines where they run parallel for some distance. This is the main contributing interference source in the case of a.c. corrosion risk.

Capacitive coupling occurs due to the placing, temporarily or permanently, of pipework / pipelines in close proximity to overhead power lines. Capacitive coupling can also occur when pipelines and insulated power cables are in direct contact with each other i.e. touch each other.

Resistive coupling occurs when current discharges from a power line cable to earth. This can result in an increase in the pipeline touch potential when there is a fault associated with a particular tower and a.c. corrosion can occur during the short-term interference events. Lightning can also be a source of EPR. A lightning strike on or near a pipeline / earth grid may cause EPR, or a flashover may occur if a pipeline is too close to a power line.

3.3 A.C. Corrosion

A.C. corrosion poses a significant risk to pipeline systems and can result in accelerated corrosion on pipelines that are subjected to a.c. interference above defined levels, even if the cathodic protection criteria stated in BS EN 12954 are achieved. Appendix E of this GPG contains information on the UK's experience of a.c. corrosion and provides information on a number of case histories.

Where a.c. corrosion is occurring, then failure of a standard wall thickness pipeline system by localised corrosion could occur within a few years, if the corrosion rates are at the upper end of the possible range for a.c. corrosion , Thus, where a.c. interference does occur, it is important to ensure that it is managed and controlled within defined limits to mitigate the a.c. corrosion risk. If a corrosion risk is identified, then prompt action is required to control the a.c. corrosion risk and prevent damage to a pipeline system.

3.4 Background Information

Section 9.0 of this GPG provides details of reference publications related to the a.c. interference on buried pipelines. There are a number of published standards and informative reference documents that are available and provide good guidance and advice on the topic of a.c. interference and a.c. corrosion on pipelines. It is recommended that operators consult these documents to obtain additional guidance and information as appropriate.

Canadian Energy Pipeline Association "AC Interference Guideline Final Report - June 2014. [9], CIGRE TB 95 Guide on the influence of high voltage a.c. power systems on metallic pipelines [10] and the INGAA Foundation Report [11] in particular provide good guidance.

Appendix A provides a list of the abbreviations and three letter acronyms used in this document. Appendix B provides a list of definitions relevant to the subject under discussion in this document.

Appendix C provides the details of a typical questionnaire and information that powerline operators would require from pipeline operators, whilst Appendix D provides the typical information that pipeline operators would require of each power line operator to assess or model the a.c. interference risk.

The information the developers of new power cable systems should provide, and request of pipeline operators is detailed in Appendix E. In the UK promoters of new power systems particularly those associated with offshore energy developments or HVDC power connections have not often given sufficient consideration at an early stage in a project to the affect new power systems or modifications to existing power cable systems can have on buried utilities.

The information detailed in Appendices C and D details information that would typically be required by companies engaged to determine the short term and long term a.c. interference levels on pipelines using proprietary software packages. Typical questionnaires have been produced so that both powerline and pipeline operators can have a timely appreciation of the nature of the information required. It is essential that pipeline and power system operators agree the nature of any information required.

Appendix E provides background information on the published UK experiences in relation to a.c. corrosion.

4. AC CORROSION CRITERIA

The criteria for the mitigation of a.c. corrosion on pipelines should be based upon the guidance detailed in BS EN ISO 18086. The information on relevant criteria is summarised in this GPG.

NACE has recently published a guide on a.c. corrosion risk assessment, mitigation and monitoring namely NACE SP 21424. The latter standard provides good guidance but the acceptance criteria for a.c. corrosion do differ slightly to those proposed in BS EN ISO 18086. The guidance in this GPG is that only BS EN standards should be used to determine acceptance criteria to mitigate a.c. corrosion risk on pipelines in the UK.

The present guidance in the BS/EN standards is that the design, installation and maintenance of cathodic protection systems shall ensure that the levels of a.c. voltage on a pipeline are such that a.c. corrosion does not occur. BS EN ISO 18086 advises that since the conditions vary for each situation, a single threshold value for a.c. voltage cannot be applied. Protection against a.c. corrosion is achieved by reducing the a.c. voltage and current densities on a pipeline as follows:

- As a first step, the a.c. voltage on the pipeline should be decreased to a target value, which should be 15V rms or less. This value is measured as an average over a representative period of time (e.g. 24 hours) and as a second step, effective a.c. corrosion mitigation can be achieved by complying with the criteria defined in BS EN 12954:2001, Table 1 and:

  - Maintaining the a.c current density (rms) over a representative period of time (e.g. 24 hours) to be lower the 30 Am^{-2} on a 1 cm^2 coupon or probe.

  or

  - Maintaining the average cathodic current density over a representative period of time, (e.g. 24 hours), lower than 1 Am^{-2} on a 1 cm^2 coupon or probe if a.c. current density (rms) is more than 30 Am^{-2};

  or

  - Maintaining the ratio between a.c. current density ($J_{a.c.}$) and d.c. Current density ($J_{d.c.}$) less than 5 over a representative period of time, (e.g. 24 hours).

NOTE: Current density ratios between 3 and 5 indicate a small risk of a.c. corrosion. However, in order to reduce the corrosion risk to a minimum value, smaller ratios of current density lower than 3 would be preferable.

BS EN ISO 18086 also advises that “Further information is provided in Annex E of the standards. Effective a.c. corrosion mitigation can be also demonstrated by measurement of corrosion rate”.

It is considered in this GPG that the a.c. voltage criterion of 15V rms in relation to a.c. corrosion risk given in BS EN ISO 18086 had been selected based upon historical data, as voltages in excess of the latter value have been considered in the past to provide a touch potential risk to personnel working on pipelines and the 15V rms limit has now also been applied to the mitigation of a.c corrosion risk. The permissible a.c. voltage value of 15V rms on pipelines has been included in BS EN ISO 18086 and applies to mitigation of a.c. corrosion risk. Thus, in order to mitigate against a.c corrosion the a.c. voltage on a pipeline system shall be less than 15V rms. However, the latter step is only the first step in the reduction of a.c corrosion risk.

DD CEN/TS 15280 [12] did give a maximum a.c. voltage limit on pipelines of 10V rms for soils of resistivity greater than 25 Ohm m and 4V for soil of resistivity less than 25 Ohm m. However, subsequent experience since 2005 and mainly in Europe has shown that the a.c. voltage limit alone should not be used as the basis for assessment of a.c. corrosion risk. Thus, recent standards on a.c. corrosion risk have excluded any specific a.c voltage limit on pipelines in certain soil resistivities.

The latest standards for a.c. interference on pipelines do not give an a.c. voltage limit in relation to a.c. corrosion risk, as a.c. corrosion has been known to occur at voltages less than 4V in low resistivity soils, i.e. soils of resistivity less than 25 Ohm m, whilst in soils of resistivity greater than 25 Ohm m a.c. corrosion has been found to occur at voltages less than 10V.

The UK and international experience on a.c. corrosion has shown that the a.c. voltage alone cannot be used to confirm if there is an a.c. corrosion risk, as a.c corrosion can occur at relatively low a.c. voltages. The a.c voltage levels can be used to provide an indication as to whether further investigation is required and the a.c corrosion risk needs to be evaluated. Ignoring the polarisation resistance, the a.c. current density at a coating defect with a diameter d is given by equation 1) extracted from BS EN 50162, which although the latter standard relates to d.c. current density the same formula applies to a.c current density.

$$I = \frac{8V}{\rho \pi d} \qquad (1)$$

Where I = Effective AC current density (Am^{-2})
V = AC voltage on the pipeline (Volts)
ρ = soil resistivity (Ohm m)
d = defect diameter (m)

Equation 1) shows that the current density increases inversely with defect diameter and is related to soil resistivity. The voltage that is required on coating defects of $1cm^2$ surface area in soils of different resistivity to ensure that the a.c. current density is less than 30 Am^{-2} is an important parameter.

Soil resistivity is related to a.c. corrosion risk. The lower the soil resistivity the higher will be the a.c. corrosion risk on a pipeline, if a pipeline is affected by a.c interference such that the a.c. discharge current density values are in excess of the levels given in BS EN ISO 18086. The soil resistivity at the pipeline burial depth provides an indication of level of risk of a.c. corrosion. BS EN ISO 18086 relates the soil resistivity to a.c. corrosion risk as detailed on Table 1.

Soil Resistivity Ohm m	AC Corrosion Risk
0 to 25	Very High Risk
25 to 100	High Risk
100 to 300	Medium Risk
>300	Low Risk

Table 1 Relationship between soil resistivity and a.c. corrosion risk

It is important to confirm the soil resistivity at the pipeline burial depth along a pipeline route to identify high risk a.c. corrosion locations. This applies to both existing pipelines where an assessment of a.c. corrosion risk is required and for the design of a.c. corrosion mitigation and monitoring systems on new pipelines.

It is important to ensure that in the case of both new and existing pipeline systems that where there are particularly aggressive soil conditions e.g. salt marshes that these are identified, and suitable CP monitoring facilities are installed at those locations or as close as possible to them. CP test facilities in higher resistivity or less aggressive soil condition locations may not give a true indication of a.c. corrosion risk.

As far as the a.c. corrosion risk is concerned, the a.c. current density is the measurement that is the primary parameter to consider for assessment of risk. However, when assessing a.c. corrosion risk, using more than one acceptance criterion is recommended; as it is important to understand the limitations of the monitoring techniques employed.

The ratio between a.c. current density and d.c. current density is an important parameter. Thus, it is important to measure the d.c. current density in addition to the a.c current density to fully evaluate the a.c corrosion risk. If the d.c. current density is less than 1 Am^{-2} then NACE SP 21424 permits a higher a.c current density criterion of 100 Am^{-2}.

However, BS EN ISO 18086 simply advises that where the a.c. current density exceeds 30 Am^{-2} then the average d.c. current density over a representative period of time e.g. 24 hours should be lower than 1Am^{-2} to provide effective control of a.c. corrosion. BS EN ISO 18086 does however not give a limit on permissible a.c. current density in such a situation and that is considered to be an omission and in the absence of further guidance the limits in NACE SP21424 may be considered.

The a.c./d.c. current density ratio is only of relevance in assessing the a.c. corrosion risk if the a.c. current density exceeds the minimum criterion of 30 Am^{-2}.

BS EN ISO 18086 advises that maintaining the ratio between a.c. current density (Ja.c.) and d.c. current density (Jd.c.) less than 5 over a representative period of time, (e.g. 24 hours), would mitigate the a.c. corrosion risk. BS EN ISO 18086 further advises that current density ratios between 3 and 5 indicate a small risk of a.c. corrosion. However, in order to reduce the corrosion risk to a minimum value, smaller ratios of current density lower than 3 would be preferable.

The a.c. current density is related to the soil resistivity at a given location for a specific a.c. voltage. Table 2 gives the anticipated a.c. current density on a 1cm^2 coupon at a pipe to soil potential of 10Vrms.

Soil Resistivity Ohm m	AC Current Density Am^{-2}
1	2253
5	451
10	225
25	90
50	45
100	23

Table 2 Relationship between a.c. current density and soil resistivity a.c. voltage of 10Vrms

It can be seen from Table 2 that soil resistivity has a significant influence on the a.c. current density, hence corrosion risk. Areas of low soil resistivity e.g. salt marshes, chloride contaminated soils or peaty soils, (soil resistivities less than 25 Ohm m), are high risk locations for a.c. corrosion. The spread resistance of a coupon is related to the local soil resistivity. The spread resistance is typically quoted in terms of Ohms m^2.

The guidance in the latest standards is that at current densities in excess of 30 Am^{-2} there is an a.c. corrosion risk. The previous standards and some of the publications referenced in this GPG reference different a.c. current density criteria, but this GPG recommends that the guidance in BS EN ISO 18086 should be followed and current densities in excess of 30 Am^{-2} should be considered to indicate a risk of a.c. corrosion.

Experience has shown that generally, as the a.c current density increases above 30 Am^{-2}, then so does the corrosion rate see Figure 1 and Figure 2.

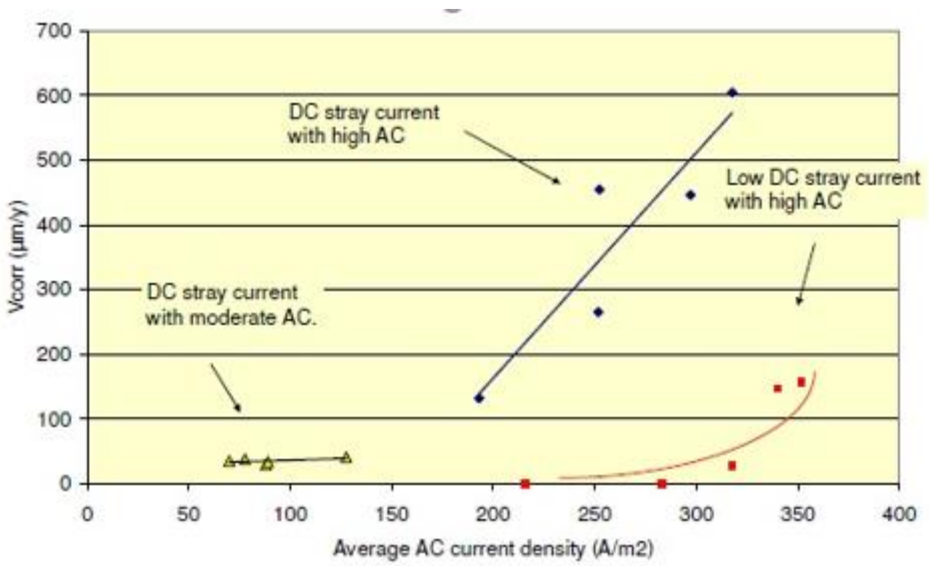


Figure 1 Relationship between Corrosion Rates and Current Density from Nielsen [13]

It can be seen from Figure 1 and Figure 2 that there is a correlation between a.c. corrosion rate and current density but it is not possible to predict the corrosion rate based upon measurement of a.c. current density alone. To ascertain the ongoing a.c. corrosion rate in a given location then corrosion rate measurement devices e.g. ER probes need to be employed.

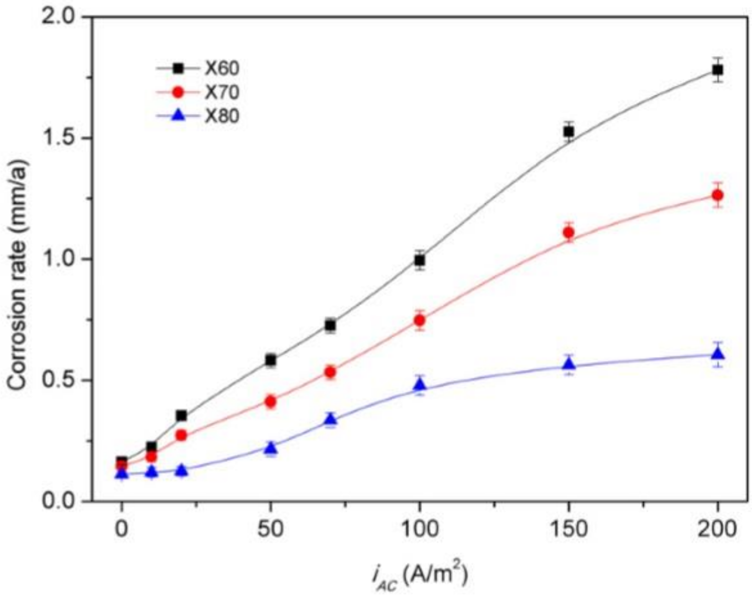


Figure 2 Relationship between AC Corrosion Rates and Current Density from Y Guo et al on different API 5LX Pipeline Steels [14]

It is essential that data logging is carried out at high risk locations for a.c. corrosion to determine a.c. pipe to soil potential and current density time dependent variations. Data logging at different times of the week should be carried out as measurements at weekends may not generally give representative values of a.c current density, since the load on power lines would be lower than during the week. Therefore, it is recommended that data logging is carried out over a 7-day period.

Data logging should also be carried out at different times of the year when the loads on the power lines are expected to vary. It should also be carried out during weekdays when industrial premises are operating and not necessarily at weekends, particularly if data logging is only performed over 24 hours. Ideally data logging should be carried out for longer periods of time e.g. 7 days with data logging at intervals of greater than one reading every 10 minutes to monitor a.c interference from overhead power lines. In the case of interference from a.c. traction systems higher monitoring frequencies are required in the region of one reading a second.

The induced a.c voltage on a pipeline is generally compared with the powerline operating data to verify the accuracy of any mathematical model and the power load data in the UK is typically only available in 15-minute increments from the power line operator. Thus, data logging at intervals between once every 1 to 5 minutes would typically be suitable for assessing a.c. corrosion risk from overhead power lines and comparing this with power line load data.

However, for interference from a.c. traction systems where interference levels can vary over relatively short periods of time then shorter intervals of between 0.1 to 5 seconds would be considered.

The measurement of a.c. current density once or twice a year at a CP test facility over a 30 second period will not give a representative indication of the a.c corrosion risk on a pipeline. It will not provide fully representative values of a.c. current density or voltage but may give an indication of whether a specific location is a high risk or not in terms of a.c. corrosion.

In the case of a.c. interference on pipelines close to power stations if the power station is not operating at the time a.c. pipe to soil potential readings are recorded then a.c voltages would be a lot lower than those when the power station is on line and would not fully reflect the a.c. corrosion risk.

For pipelines routed close to power station pylons it is important to identify if the power station was operating at the time any survey or testing was carried out.

Thus, in the case of pipelines supplying gas to power stations and routed close to powerlines then a.c. interference monitoring should ideally be performed when the power station is operating at or close to full load to ascertain the true a.c. corrosion risk.

Any data loggers used to monitor a.c. interference should also be able to provide mean values of current density and voltage and have sufficient a.c rejection capability to ensure spurious readings are not recorded.

Data logging plots should be carried out on pipelines at routine intervals during the pipeline life since there could be a considerable variation in the a.c. current density with time. Thus, taking one a.c. current density reading at a test post every 6 months may provide a good indication of the level of risk, but it may not provide fully representative values. Measurements of a.c. current densities every 6 months would identify high risk locations where further monitoring using data loggers should be conducted.

If there are borderline values of a.c. current density i.e. values close to the 30 Am^{-2} criterion recorded during 6 monthly monitoring checks, there could easily be periods of time when the a.c. current density exceeds the 30 Am^{-2} criterion. Thus, the use of data loggers to provide long term monitoring data should be considered at such locations.

In relation to mitigation of the a.c. corrosion risk, other protection criteria are also important. One of the methods of controlling a.c. corrosion risk involves maintaining the 'ON' pipe to soil potential within a specified range.

BS EN ISO 18086 advises that a significantly negative 'ON' potential can result in high cathodic current densities and in a strong change in the soil chemical composition, spread resistance and an increased reduction of oxide layers at the pipeline surface.

A.C. corrosion can be prevented when applying a sufficiently negative 'ON' pipe to soil potential to avoid any metal oxidation due to the presence of a.c. interference. As a consequence, the required level of the 'ON' potential is related to the induced a.c. voltage on the pipeline. The use of more negative 'ON' potentials can be indicated in the presence of d.c. stray current interference on a pipeline. However, the 'ON' potentials would need to be significantly negative to mitigate the a.c. corrosion risk and at such negative potentials cathodic disbondment, osmotic and non-osmotic blistering could occur on the pipeline coating, see Figure 3.

Coating disbondment, would be a problem with thin film FBE coatings at sufficiently negative potentials.

Most pipelines are not susceptible to significant levels of d.c. stray current interference and the use of a negative 'ON' potential to apply increased CP levels is not really practical due to the increased risk of cathodic disbondment of pipeline coatings and hydrogen embrittlement of high strength steels i.e. X80 and above.(L555).

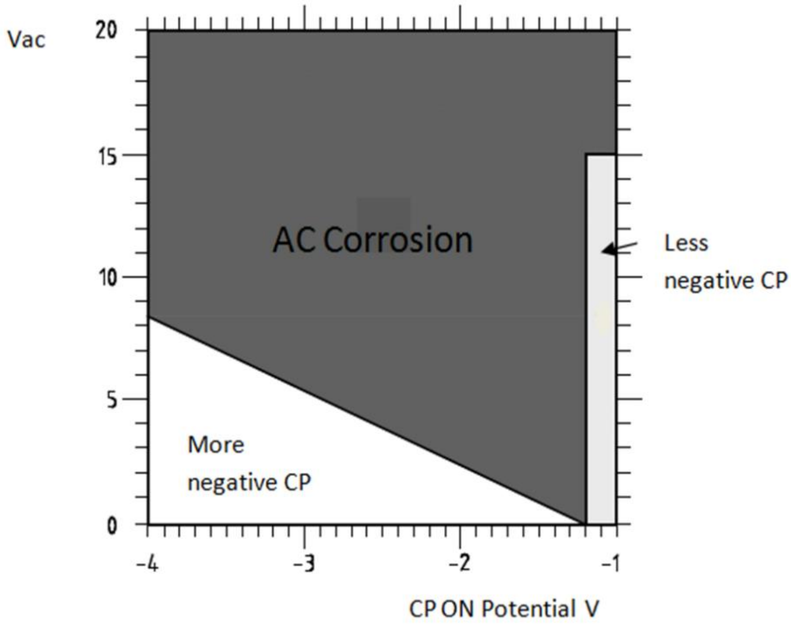


Figure 3 AC corrosion likelihood with a.c. voltage and d.c. 'ON' potential extracted from BS EN ISO 18086

Figure 3 shows that increase in the CP 'ON' potential in a more negative direction can control the a.c. interference risk as it increases the d.c. current density, but it is not really practical to use this method in the field as significantly negative pipe to soil potentials may cause problems as detailed above. Thus, for most UK pipelines, the control of the a.c. corrosion risk by control of the d.c. 'ON' potential is not recommended.

BS EN 12954 states that "Protective coatings can become damaged or polarized under the influence of cathodic protection. Coated structures should not generally be cathodically polarized beyond -1,2 V $Cu/CuSO_4$ (IR Free). Values more negative than -1.2V $Cu/CuSO_4$ (IR Free) may be used if experience or data for the particular coating system and its application demonstrate that more negative values do not cause significant detrimental coating damage or disbondment in the field".

NACE SP 21424 advises that Increasing the level of cathodic protection may be attempted in order to mitigate AC corrosion. However, the standard states that in the a.c. corrosion scenario, this will have the opposite effect, since the increase of CP current density further decreases the spread resistance at the coating defect due to the production of ions such as OH^- (alkalization).It is noted that the spread resistance may also increase rather than decrease under CP conditions as a result of the formation of high resistive films, such as magnesium-or calcium hydroxides or -oxides, on the steel surface at elevated pH conditions, if these earth alkaline cations are present in the soil. These conditions then lead to a decreased AC corrosion risk. Decrease in the spread resistance will increase the a.c. corrosion risk, whilst an increase in spread resistance will reduce it as the a.c. current density will reduce at a given a.c. pipe to soil potential.

Nielsen [13] has reported data on the relationship between a.c. corrosion rate, d.c. pipe to soil potential and a.c. voltage see

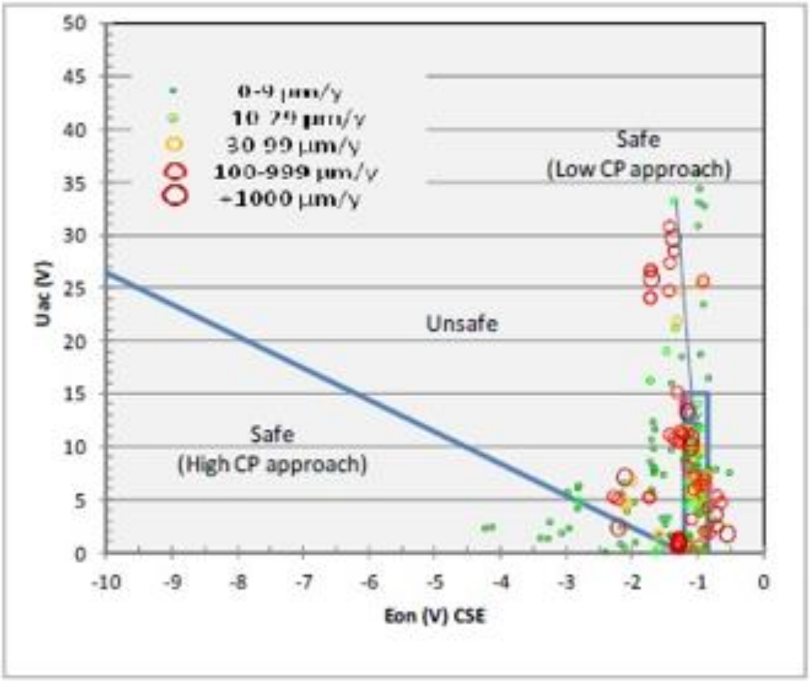


Figure 4 Relationship between Corrosion Rates and AC Voltage Current density From Nielsen [13]

A relatively positive 'ON' potential has only a limited effect on spread resistance. Higher negative 'ON' potentials increase the cathode current density and rate of hydroxyl ion formation and reduce spread resistance. The alkalinity produced at the cathode surface will cause a local reduction in resistivity and decrease the spread resistance with increase in cathode current density.

BS EN ISO 18086 advises that " A negative 'ON' potential can result in a high cathodic current density and in a strong change in the soil chemical composition, spread resistance and an increased reduction of oxide layers.

A.C. corrosion can be prevented when applying a sufficiently negative 'ON' potential to avoid any metal oxidation due to the presence of a.c. interference. As a consequence, the required level of the 'ON' potential is related to the induced a.c. voltage on the pipeline.

Less negative 'ON' potentials will have no adverse effect on the coating adhesion and disbondment risk. They can result in insufficient cathodic protection according to the limiting potential criteria indicated in BS EN ISO 15589-1 [15] and BS EN 12954.

When choosing an a.c. corrosion prevention system based on a less negative *E*on cathodic protection level, it might be necessary to install additional CP stations along a pipeline route to limit the drain point potentials but still achieve sufficient spread of potential along the pipeline length. However, applying an 'ON' potential criterion that is as positive as possible, while still maintaining the 'OFF' potential criteria given in BS EN ISO 15589-1, will result in a decreased a.c. corrosion likelihood.

BS EN ISO 18086 advises that theoretical and practical experiences have shown that the following methods can be used to solve a.c. interference problems.

First scenario: "more negative" cathodic protection level. In this case, one of the three parameters below, in order of priority, can be applied:

The following formula should be satisfied:

1) $$\frac{U_{AC}}{E_{ON} - 1.2} < 3$$

U_{AC} = AC rms pipe to soil potential

E_{ON} = The pipe to soil ON potential

NOTE −1.2 V against Cu/$CuSO_4$ is the limiting critical potential, (see BS EN ISO 15589-1). Choosing a more positive value would create a less conservative result in the calculated ratio for given Ua.c. and Eon values.

Or

2) AC current density < 30 A/m^2;

Or

3) $\frac{J_{AC}}{J_{DC}} < 3$ if a.c. current density > 30 A/m^2;

J_{AC} = a.c. discharge current density Am^{-2}

J_{DC} = d.c. current density Am^{-2}

If the more negative 'ON' potential is applied to control the a.c. corrosion risk, it is important to ensure that there is no corrosion risk due to cathodic disbondment and no adverse effect on the pipeline steel from hydrogen evolution or embrittlement.

The use of the more negative potential criterion is not really an option for most pipeline systems because of the risk of cathodic disbondment on the pipeline coating.

The voltage criterion given in BS EN ISO 18086 namely equation 1) has been used to assess the a.c. corrosion risk on actual pipeline systems in the UK with an a.c. mitigation system installed. From the results obtained the a.c/d.c. 'ON' voltage ratio criterion of <3 given in equation 1) was not often satisfied, even on coupons where the a.c. current density was considerably below the 30 Am^{-2} criterion. This observation has shown that the ratio between a.c. voltage and d.c. 'ON' potential should not really be used to provide definitive confirmation that an a.c corrosion risk exists.

The a.c./d.c. voltage ratio given on equation 1) is not considered to be a practical method of assessing the a.c. corrosion risk and a certain element of caution should be exercised when interpreting data using the latter method.

The a.c. current density still remains the main assessment parameter in determining the a.c. corrosion risk. The a.c. to d.c. current density ratio provides confirmatory guidance but also has its limitations. It should be noted that the current density ratio only really applies in situations where the a.c. discharge current density exceeds 30 Am^{-2}.

Some organisations apply the a.c./d.c. current density ratio to assess a.c. corrosion risk for all a.c. discharge current densities, which is not correct.

A certain degree of caution should be exercised when just using current density data as a means of assessing corrosion risk. As the current density data obtained is totally reliant on intimate coupon to soil contact, which may not always be achieved. This aspect is discussed further in section 7.

Practical experience in the UK has also shown that in situations where a number of $1cm^2$ coupons are installed at the same test facility then a significant variation in a.c. current density can be recorded for different coupons. Caution should be exercised when interpreting data and where actions are planned based upon just one set of data, additional monitoring or coupons should be installed.

Other factors that affect the quality of the data obtained from coupons are the coupon construction with circular coupons being preferred as this would then enable equation 1) to be used to calculate soil resistivity from knowledge of the coupon spread resistance. However, other coupon geometries may also be utilised e.g. with ER probes.

The coupon exposed surface area must be $1cm^2$ not say $1.1\ cm^2$ or there will be a significant error in the current density data obtained. Thus, the surface area should be accurate and reproducible for all coupons. Operators should also note that if coupons are exposed to an a.c corrosion or general corrosion risk then the effective surface area may not be $1cm^2$ if corrosion has occurred over time then the actual geometric surface area could be higher. This would have an effect on the a.c. current that will be discharged and provide erroneous values for a.c discharge current density.

5. AC INTERFERENCE MITIGATION AND CODE REQUIREMENTS

5.1 Pipeline Design Code Requirements

The pipeline design code requirements in relation to a.c. interference should be identified and complied with. In the case of PD-8010-1 [16] it states “If personnel safety is at risk from a.c. voltages on the pipeline or if an a.c. corrosion risk exists, measures should be taken to mitigate the risk. These should include:

- earthing laid parallel and connected to the pipe.
- earthing mats at valves.
- connection of polarization cells or their solid-state equivalent across electrical isolating devices. to connect the pipeline to earth and to protect the electrical isolating device.
- dead front test posts to prevent third-party contact.

NOTE 1: One of the methods of monitoring the a.c. corrosion risk is by measuring the a.c. current flowing at a buried coupon installed at the location where the a.c. interference is believed to be at its greatest. These coupons normally comprise a coated metal plate with an exposed bare steel area of 1cm^2. The coupon is normally connected to the pipe via a shunt that enables both the a.c. current flow and the d.c. current flow to be measured.

NOTE 2: Mitigation measures may be installed retrospectively, but this carries a risk of a.c. corrosion occurring before installation is complete. The installation of further mitigation measures might be necessary if the power line load increases.

PD 8010-1 advises that the need for a.c. mitigation should be identified at the design stage and this may be achieved by computer-modelling of the power line/pipeline interaction.

Pipeline design standards requirements in relation to a.c. interference should be assessed, but it should be noted that they may not always specify the latest guidance in relation to a.c. interference risks. It is considered to be beneficial to seek expert advice on a.c. interference issues and to follow the guidance in this GPG in addition to the information included in the relevant pipeline design code.

In any event, the guidance to monitor and mitigate the a.c. corrosion risk should be based upon this GPG and BS EN ISO 18086.

5.2 AC Corrosion Risk Reduction Methods

There are three different approaches to prevent a.c. corrosion; - one is to limit the a.c. current flowing through a defect, one is to control the cathodic protection level, and the other is to ensure that any coating remains defect free. These approaches are not mutually exclusive.

The creation of a defect free pipeline coating is not considered to be a viable option to control the a.c. corrosion risk as existing over the line coating defect surveys cannot locate all coating defects. In addition, a reduction in the number of coating defects could result in an increased a.c. current density on the coating defects that remain, which could also result in an enhanced a.c. corrosion risk at certain locations.

Stringent efforts are always taken during pipeline construction to identify and repair coating defects, but defects still occur, and it would not be practical to ensure a pipeline coating is defect free and remains defect free for the life of a pipeline.

The DCVG over the line survey technique is a sensitive coating defect identification technique but it does have its limitations, especially in low resistivity soils and it may not be possible to locate all coating defects on a pipeline system after pipeline installation.

For one pipeline with known corrosion features in the UK where the soil resistivity was less than 15 Ohm m a DCVG survey was conducted and none of the external a.c. corrosion defects identified on any ILI feature were identified. The limited success from the DCVG technique in low resistivity soils may be associated with the survey technique, where small percentage IR defects may not have been specifically recorded or where large DCVG indications are detected these may hide smaller ones. In low resistivity soils the IR drop at a defect location will be low and difficult to detect. In low resistivity soils, it may be advisable to a combination of coating defect surveys e.g. DCVG and ACVG to locate coating defects. It is certainly advisable to ensure all DCVG indications no matter how small are recorded.

If a defect was present in a trenchless crossing section for example it may not be possible to access the defect or carry out a repair. It is believed it is not practical or possible to achieve a defect free coating system.

Conventional over the line survey techniques do have limitations on the ability to identify pipeline coating defects where the depth of burial is greater than about 3 to 4m.

Increase in the d.c. pipe to soil potential is a method of controlling the a.c. corrosion risk but is not considered to be an option on most modern coatings namely FBE and 3-layer coatings because of the risk of cathodic disbondment.

The preferred method of control of a.c. interference risk is by reducing the a.c. discharge current density at coating defects through the installation of earthing on the pipeline. The a.c. current would then discharge to earth through the earth system installed on a pipeline and the current density through defects in the coating system should be reduced to safe limits.

However, there are other measures that may also be employed to reduce the risk of a.c. interference. On a new pipeline one measure is to use isolation joints to create shorter pipeline lengths and reduce the magnitude of a.c. interference in other sections of a pipeline. If this approach is considered, it is really only practical on new pipeline systems and needs to be considered at the route selection and pipeline design stage. Splitting the pipeline system into shorter electrically continuous sections can increase the quantity of earthing material required in other pipeline sections. It is therefore preferable to undertake mathematical modelling to ascertain if there are benefits in a given situation of installing insulation joints.

In very low resistivity areas where there is a high a.c. corrosion risk. The diverted, new or replacement pipeline sections can be installed in a high resistivity backfill when the pipeline is installed by the open cut technique. The use of a high resistivity backfill e.g. sand or limestone dust would assist in reducing the a.c. discharge current density at coating defects on the pipeline. Washed sand backfill around a pipeline section would ensure that the pipeline is exposed to a lower corrosion risk simply because the soil resistivity in intimate contact with the pipeline would be high >100 Ohm m and that would limit a.c. discharge current density at any exposed coating defects.

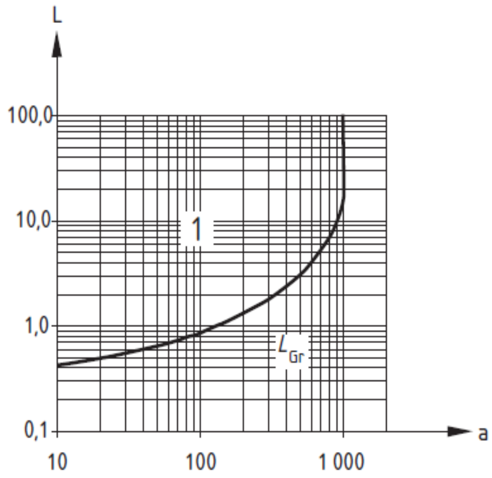
If selected backfill is used it is important to ensure that any a.c. coupons are installed in the same environment as the pipeline so that correct evaluation of a.c. monitoring data can be undertaken.

Particular attention should be paid to pipeline diversions and modifications where the new pipeline coating has a considerably higher dielectric strength than the existing pipeline e.g. connecting an FBE coated pipeline to a coal tar enamel coated pipe. In such situations, where a.c. interference is possible the a.c. current density at the higher coating quality sections can be a lot higher than on the lower coating quality sections and may be more susceptible to a.c. corrosion

The above listed measures should be considered on a case by case basis, but the use of earthing compatible with the pipeline CP system is generally the preferred option to control the a.c. corrosion risk especially on existing pipelines.

5.3 Guidance on Powerline Pipeline Influence

DD CEN/TS 15280 did give good guidance on the relationship between length of parallelism of overhead power lines and separation distance and whether verification of the level of a.c. interference is required (see Figure 5).



Key
L Length of parallelism (km)
L_{GR} Limit length
a average distance between the pipeline and the electricity line calculated on the total length of the parallelism (m)
1 Verification is necessary

Figure 5 Limit Length LGR and distance a from pipeline when laid parallel to a 50 Hz 3 phase HV power line for calculation from DD CEN/TS 15280-2006

The curve in DD CEN/TS 15280 was removed from the updated dated standard BS EN 15280 as there are so many other variables that need to be considered when determining risk of a.c. interference e.g. power line operating currents, distance between phases, operating voltages, coating conductance and soil resistivity. Thus, whilst Figure 5 does give an indication as to the distances and extents of parallelism that should be considered in the evaluation of a.c, interference risk.

Figure 5 should not however be used to provide definitive guidance such that an assessment is not required if the pipeline and power line separation and parallelism fall within the limit L_{GR} on the curve in Figure 5.

INGAA has produced a report detailing the relationship between various factors on the a.c. interference risk e.g. pipeline power line separation, power line current and crossing angle on the level of a.c. interference for a 345kV power circuit. This information is summarised on Tables 3 to 6.

Separation Distance (m)	Severity of HVAC Risk Ranking
D < 30	High
30< D> 150	Medium
150< D>300	Low
300< D> 750	Very low

Table 3 Separation distance between pipeline and power line

Powerline Current (Amps)	Severity of HVAC Risk Ranking
1000	Very High
500< I> 1000	High
250< I> 500	Medium-High
100< I> 250	Medium
I<100	Low

Table 4 Relationship between power line current and AC risk ranking

Parallelism Length L (m)	Severity of HVAC Risk Ranking
>1500	High
300< L> 1500	Medium
L<300	Low

Table 5 Separation distance between pipeline and power line

Crossing Angle Θ	Severity of HVAC Risk Ranking
Θ< 30	High
60< Θ> 30	Medium
Θ>60	Low

Table 6 Relationship between power line pipeline crossing angle and risk ranking

It is considered that the tables should give good indicative guidance to assess high and low risk a.c. situations.

CIGRE TB 95 also gives guidance on the relationship between zone of influence and power line pipeline separation.

The zone of influence *d* has to be considered when: -

$$d = 200\sqrt{\rho}$$

Where:

d = distance from pipeline below which a.c interference has to be considered (m)

ρ = soil resistivity (Ohm m),

Thus, for 100 Ohm m soil, d should be less than 2000m.

BS EN 50443 gives slightly different guidance than CIGRE TB 95 see Table 7.

Type of AC Power System	Areas	Soil Resistivity ρ (Ohm m)	Interference Distance m	
			Normal Operation	Fault Condition
Overhead	Rural	>3,000 ≤3,000	ρ/3 1000	P 3,000
Overhead	Urban	>3,000 ≤3,000	≥300	ρ/10 ≥300
Buried	All	all	50	50

Table 7 Guidance on interference distance from BS EN 50443

5.4 AC Corrosion Monitoring

To monitor the a.c. corrosion risk it is important to determine the a.c. discharge current density on a pipeline. This can only be carried out via the use of a coupon with an exposed surface area of 1cm^2. The coupons should be specifically designed for use on cathodically protected pipelines.

When a.c. coupons are installed and used for monitoring purposes to determine the risk from a.c. corrosion, then any d.c. coupon also connected to the pipeline should be disconnected when current density readings are taken. Temporary 'T' handle coupons can be used to provide an initial assessment of risk, if there are no permanent coupons installed, (see Figure 6). These have exposed steel tips with 1cm^2 surface area that are driven into the ground as far as practical.

The 'T' handle type coupons are useful for initial investigations, but the data obtained should be considered as indicative. Surface soil resistivity values will be different to those at the pipeline depth and if the surface resistivity is high that will mean that the a.c. current density may be lower than at the pipeline depth.

The length of the 'T' handle coupon should be selected so that it will not damage buried cables or other utilities at the probe installation location and the probe length is generally limited to 0.5m.

There are a number of different suppliers of a.c. coupons i.e. coupons that have an exposed steel surface area of 1cm^2 and the coupons should ideally have a factory connected cable rather than use cables connected to coupons in the field. It is imperative that the cable to coupon connections are effectively insulated and the coated steel surface area is minimised so that this does not result current discharge from the coupon connection or any coating leading to erroneous readings. The coupons are used specifically to assess the risk of a.c. and d.c. interference on buried pipelines.

The coupon cable conductor size should be a minimum of $10mm^2$ and the cable colour should comply with the pipeline operator requirements to indicate function as an a.c. coupon. In the UK, $10cm^2$ d.c. polarisation coupon cables would typically be coloured blue and $1cm^2$ a.c. coupons cable typically coloured white.

It is important to ensure a clear distinction between a.c. and d.c. coupons connected into any CP test post. This can be achieved by the use of proprietary cable markers. D.C coupons when installed alongside a.c. coupons should always be disconnected when a current reading is taken through an a.c. coupon.

Figure 6 T Handle type temporary 1 cm^2 surface area a.c coupon

The preferred coupons to employ are those that are circular and have a limited exposed coated steel surface area. This is because a.c. current can also flow through the coating and provide a source of error. A typical a.c. coupon is shown on Figure 7. It is essential that the coupon surface area is accurate as even a small change in coupon diameter can result in significant errors in recorded current density.

On installation coupons need to be installed so that the exposed steel surface area is pointing away from the pipeline. They should be carefully compacted in graded local soil and the coupon spread resistance checked to confirm it is of the expected value, which is typically less than 1 Ohm m^2 before the coupon and any other monitoring equipment is completely backfilled. Similar checks to confirm probe spread resistance before backfilling should be made with ER probes. Once backfilled it will not be easy to replace any as installed probe.

On pipelines that are susceptible to an a.c. interference risk, the a.c coupon dimensions and geometric surface area can change as a result of corrosion and this can lead to erroneous a.c. current density data. Operators should be aware of the latter risk when analysing data on coupons particular where it is known that a.c. corrosion may be occurring, and coupons have been installed for some time.

Decisions are frequently made in relation to installation of expensive a.c. mitigation systems based upon the current data from coupons. It is important therefore that operators are aware that errors can occur in data measurement depending upon the coupon construction and installation.

Some older coupon designs included coupons that were strapped to pipelines but the cable to coupon connection was made on site rather than under factory-controlled conditions. The later design it is considered was not ideal and can lead to errors and is not recommended for new pipelines.

When coupons are installed, they should always be installed in local soil at the pipeline burial depth and in intimate contact with the local soil. Only local soil should surround a coupon and the coupon should be installed with the steel face pointing away from the pipeline at a distance from the pipeline of approximately 100mm. BS EN ISO 18086 advises “The *coupon or probe should have and maintain effective electrical contact with the surrounding soil – unless lack of contact is part of the purpose of monitoring. During the installation process, the soil around the coupon or probe should be compacted to prevent settlement and voids forming around the coupon or probe. These voids could result in loss of full contact between the coupon or probe surface and the surrounding soil*”

The current flow through a coupon can be measured through a shunt in series with a coupon or with suitable test equipment capable of measuring true rms with sufficient a.c. rejection capability. In low resistivity soils the typical shunt resistance of 10 Ohms can be a significant percentage of the coupon spread resistance. Thus, if the coupon spread resistance is 1000 ohms then a 1% error in measurement of current density will be achieved if the shunt resistance is 10 Ohms. However, if the coupon spread resistance is 100 Ohms then the use of a10 Ohm shunt or 200mV 20mA will cause a 10% error in current measurement. Guidance on measurement techniques for CP applications is given in BS EN 13509 [17]

Figure 7 Typical a.c. coupon

5.5 Competency and Certification

It is recommended that any a.c interference monitoring, and mitigation systems designs should be carried out by personnel having the levels of competency and certification as defined in BS EN ISO 15257 [18].

Any a.c monitoring and mitigation system designs should be carried out by a Level 4 Senior Cathodic Protection Engineer as defined in BS EN ISO 15257.

The pipeline operator should however confirm that personnel employed in design and monitoring process on pipelines susceptible to a.c. corrosion, even if BS EN ISO 15257 certified have the required levels of experience and competency in assessment of a.c interference risks on pipelines.

In relation to the modelling of the a.c. interference on pipelines, only companies with demonstrable experience in the use of proprietary software should be used to conduct the a.c. interference modelling studies. The agency employed for mathematical modelling studies should be certified in the use of the software by the software provider for short and long-term interference studies. Only software packages with a proven track record in modelling a.c. interference on pipeline systems should be used for mathematical modelling studies.

Personnel undertaking routine monitoring of a.c. interference on pipelines should also have the necessary levels of competency, certification and understanding.

It is advisable for pipeline operators to provide training to operatives to ensure that they are fully conversant with the nature of the monitoring required on pipelines affected by a.c. interference and understand the relevant safety risks.

Certification of personnel to BS EN ISO 15257 would not provide the required level of awareness in relation to the electrical safety risks associated with work on pipelines and operators should provide relevant training to ensure personnel are aware of safety risks and safe working practices. It is important that risk assessments and method statements are produced for a.c. interference monitoring and personnel undertaking the work comply with the risk assessments and method statements.

Guidance on the electrical safety considerations for routine monitoring on pipelines susceptible to a.c. interference is given in UKOPA/TBN/005.

6. INDUCED A.C. VOLTAGE LEVELS AND ASSESSMENT OF RISK

6.1 Introduction

Calculations of induced voltage for different situations can be undertaken based upon the guidance given in the documents referenced in this GPG. This GPG does not provide calculation examples but provides references for calculation methodology for both long term and short term a.c. interference. However, ISO 21857 and AS/NZS 4853 [19].do provide examples of calculation methods and should be used for reference.

It is recommended that companies which specialise in assessment of a.c. interference from cable systems, who employ suitability qualified electrical engineers undertake the modelling work. Only proprietary finite element modelling software with a proven track record for use in modelling induced a.c. interference levels should be used for any studies.

6.2 Induced Voltage Levels Buried Cables on Pipelines

The a.c. interference levels on buried pipelines from buried cables should be assessed based upon the guidance given in CIGRE TB 95. It should be noted that the interference levels on pipelines from buried cables are generally lower than for overhead power lines.

The existing a.c. voltages present on a pipeline should also be taken into consideration when assessing risk of interference from new cable systems since, whilst the existing a.c. voltages may be within limits to ensure no a.c. corrosion risk prior to installation of any cable system, even a small induced voltage from a new buried cable system could add to the voltages already present on a pipeline. The addition of voltages is not a simple numerical addition and would need to be treated as vector values.

Thus, base line and post energisation data logging should be performed to confirm that any a.c. interference risk on pipelines routed in parallel with buried high voltage power lines is within manageable limits. Additional test posts and monitoring facilities may be required to confirm the a.c. interference levels if new power cable systems are installed close to an existing pipeline.

6.3 Induced Voltages Overhead Cable Systems

The long-term a.c. interference risk on buried pipelines from overhead power lines can be calculated based upon the guidance on calculation methods given in CIGRE TB 95 and GIGRE TB 290 [20] AS/NZS 4853 also provide examples of typical calculations.

There is proprietary software that can be used to model the long term induced a.c. interference on pipelines. The models can take time to run and should be conducted by specialists experienced in producing a model and using the software.

Information is required from the pipeline system operator and also the power line operator. A typical questionnaire that would be submitted to a pipeline operator is given in Appendix C and a typical questionnaire that would be submitted to the power line operator is given in Appendix D.

Most high voltage power lines have overhead earth wires in their construction. These overhead earth wires have a shielding effect on the pipeline, which will reduce the LFI in the pipeline.

6.4 Rail Traction System Interference

If pipelines cross a.c. traction systems at right angles and do not run in parallel with the traction system for any appreciable distance, then the levels of interference from a 25kV traction system should be low.

However, a.c. monitoring coupons should be installed at CP test facilities located on each side of any a.c. traction system so that the a.c. interference levels can be monitored.

Where a pipeline crosses a rail line, the crossing should be at right angles and the pipeline should be routed so that it is equidistant between rail line pylons. This will limit the ground potential rise on the pipeline during fault conditions on the traction system. Typical fault currents from on rail traction systems vary with distance from the substation with typical values in the region to 1 to 12 kA.

The pipeline should ideally be installed in a high resistivity bentonite-based alkaline grout at the crossing point of resistivity greater than 100 Ohm m. Bentonite alone if used for sleeved crossings or to provide selected backfill for open cut crossings would be have a low resistivity at 1 Ohm m and provide a low soil resistivity and thus be a high risk environment in terms of a.c. corrosion risk.

The risk in relation to pipelines in close proximity to railway systems occurs where the pipeline is routed in a parallel with the traction circuits and can collect traction return currents by resistive coupling and also inductive/capacitive coupling from the live traction cables.

BS EN 50443 advises that capacitive coupling from a railway system has to be considered in case of proximity lower than:

10 m in case of 15 kV, 16,7 Hz systems;

a) 50 m in case of 25 kV, 50 Hz systems.

BS EN 50443 advises that conductive or resistive coupling from an a.c. electric traction systems shall be considered in case of crossing or proximity lower than 5m from the nearest rail or masts or metallic components connected to the rails. However, practical guidance would be that separation distance of at least 20m should be considered between rail line and traction line earths.

Modelling of the effects of a.c. interference from a.c. traction systems should be undertaken by specialists experienced in this field. The nature of the rail electrification system would need to be established and information provided on the location of any a.c. booster stations, train frequencies on the rail line and operating currents for different scenarios. Soil resistivity data at substation locations and at 1 to 2 km intervals along route of any affected section should be obtained. The relative positions of feed and return conductors including earth wires should be confirmed, the number of substations and distance the traction circuit runs parallel with pipeline and separation distance between the two.

The maximum and normal loads on the rail system and fault current at substations and on pylons close to pipeline should be confirmed and the rail operator should provide information on the number of track circuits and power lines operating at 25 kV and their physical location. The location and type of feeder cables from substations, Location of traction return current paths and proportion of return current anticipated for each path, including rails and return screen conductor should be advised together with anticipated fault clearance times. The earth resistance target for any trackside equipment should also be confirmed.

The overhead aerial earth wire also has a shielding effect in reducing the levels of interference. No pipeline a.c. corrosion mitigation system earth should be installed underneath a rail line since during fault conditions the ground potential rise on the earth may affect rail signalling systems.

All apparatus, cabling and earth systems associated with a pipeline system installed under railway lines must be approved by the rail authority. A HAZOP and HAZCON should be carried out between the pipeline operator and railway operator for new construction activities in the vicinity of rail crossings to ensure safe operation of the pipeline and railway.

6.5 Requirements to Assess Risk

Operators should carry out an assessment of the risk of a.c interference on all metallic pipeline systems that they are responsible for. If a.c. interference is then identified as a risk, appropriate measures should be implemented to monitor and mitigate the risk.

It should be stated that not all pipelines may be susceptible to a.c. interference and corrosion. The assessment process should be documented. Pipeline operators should assess the a.c. corrosion risk and the electrical safety risk to personnel. It should be stated that not all pipelines or sections of a pipeline may be susceptible to a.c. interference. The measures to monitor and mitigate the a.c. corrosion risk should include the guidance given in this GPG and BS EN ISO 18086 plus the requirements of any specific pipeline operators codes and standards. The requirements to assess the electrical safety risk to personnel on pipelines should be based upon BS EN 50443 and UKOPA/TBN/005. Pipeline systems should be evaluated on a case by case basis.

Any assessment should be prioritised with pipelines considered to have the highest level of risk being assessed first. Details on the factors to consider in relation to existing pipelines in terms of assessment of risk are given in section 7 of this GPG.

It should be noted that the level of risk to pipeline systems should be reviewed on a periodic basis as situations may change. Thus, the process of assessment should be ongoing over the life of a pipeline system as new power lines or electrical substations may be installed in the vicinity of pipelines or the loads on existing power lines increased. If such a situation occurs, then the level of induced voltage on a pipeline may change. Power line operators can increase the load on overhead power lines without notifying pipeline operators or considering the effect increased power line loads may have on buried metallic utilities.

If pipeline diversions are required, the risk of increased levels of a.c. interference on the existing pipeline as a result of any change in the pipeline route should also be considered. Measurement of the a.c. voltage on a pipeline alone will not give a true assessment of the level of a.c. corrosion risk and on susceptible pipelines methods to monitor the a.c. current density also needs to be employed

Measurement of the a.c. voltage on a pipeline alone will not give a true assessment of the level of a.c. corrosion risk and on susceptible pipelines methods to monitor the a.c and d.c. current density through the use of 1cm^2 exposed surface area coupons also need to be employed. This will mean the installation of a.c. coupons at the pipe burial depth in appropriate test facilities. Temporary coupons may be used to provide indicative data on a.c. discharge current density.

The a.c. interference risk on all existing pipelines should be assessed in accordance with the pipeline design code requirements. All overhead power lines or a.c. substations within 1000m of a pipeline system operating at voltages of 66 kV or above should be considered.

6.6 Mathematical modelling

Where there is parallelism between pipelines and overhead or buried pipelines mathematical modelling using specialist, proprietary software can be used to determine the long term a.c. interference levels on pipelines. The long-term induced voltages can be used to calculate the induced a.c. voltage on a pipeline at a given location can be used to ascertain the likely risk of a.c corrosion. Furthermore, if there is information on the resistivity of the soil along a pipeline route then the likely a.c. current density at given locations can also be calculated.

It is recommended that companies which specialize in assessment of a.c. interference from cable systems and employ suitability qualified electrical engineers undertake the mathematical modelling work. Only proprietary software with a proven track record for use in modelling induced a.c. interference levels should be used for mathematical modelling studies on pipelines using finite element modelling.

Caution should be exercised as the mathematical models created to determine the levels of long-term interference may not be fully accurate as a number of assumptions are made when creating the model.

Experience has shown that whilst mathematical models can be useful, they may not always produce an a.c interference mitigation system design that will be fully effective and changes to the mitigation arrangement on a pipeline may be required in the future following commissioning of any a.c. mitigation system and subsequent monitoring data. Operators should validate mathematical models by undertaking appropriate a.c. monitoring on a pipeline system following installation of an a.c. mitigation system or operation of any new power cable system. On existing pipelines recorded data of a.c voltage and current density can be used to validate any model and confirm the model accuracy. To undertake system validation exercises precise information on the loads on the individual power line circuits at the time any data logging is performed would need to be established.

Mathematical modelling requires accurate information on the pipeline and power line route, details of the power system including rated and maximum loads, power cable pylon construction and details of the screen wire

The information would be required by companies engaged to determine the short term and long term a.c. interference levels on pipelines using proprietary software packages is given in Appendices C and D.

The company undertaking the modelling work should advise details of the information that will be required off power line operators to conduct the modelling studies e.g. fault current at substations and pylons, fault duration, shield wire construction, information of supply feeds to substations, power cable height above ground, power cable construction, pylon construction, whether there are any cable transpositions, operating voltage and circuit loading.

It should be noted that that on overhead power line systems where there are two circuits if one circuit is out for maintenance and only one circuit is operating the levels of induced voltage on a pipeline will be a lot higher than when both circuits are operating. In two circuit operation the electromagnetic fields can be cancelled out and reduce the interference levels on pipelines.

If the circuit loads are not balanced, then the levels of long-term interference on pipelines will be higher than when circuit loading is balanced e.g. one circuit operating at 100% of maximum load and the other at say 60% of maximum load is an unbalanced loads scenario. Pipeline operators will need to agree the circuit load scenario to be used for any model with the modelling company. The resultant model should be based upon the likely power cable load scenarios.

The likely scenarios are normal load, maximum load and rated load. The extent of circuit imbalance should also be established. The normal load is the load the power cable system will typically operate at, the maximum load is the maximum load it can operate at with the power system that is presently configured and the rated load is the load that the power cable system can theoretically carry if additional power sources e.g. larger substations are connected to it.

6.7 A.C. Corrosion Risk Assessment

Consideration should be given to pipelines routed in close proximity to a.c. traction or power systems. It is recommended that operators prioritise the level of risk as some pipeline systems will have a higher risk of a.c. corrosion than others.

The consequences of failure on a pipeline system also need to be considered, when assessing risk. Table 8 gives information on the factors that need to be considered when assessing risk.

Parameter	Limitations	Parameter	Assessment
Soil resistivity	Is data available?	Values less than 25-ohm m are high risk, 25 to 100 medium risk	Lower resistivity higher a.c. corrosion risk values if less than 10-ohm m significant risk
Power lines separation	Need to look at pipelines with 2000m of power lines	Separation distance needs to be measured	Closer HV lines to pipelines higher risk
Length of Parallelism	Anything about 300m in length should be considered	Check from accurate route drawings	Longer parallel lengths higher risk
Date of Construction	Older pipelines	Coating impedance	Older pipelines a.c. corrosion rates lower but newer pipelines coating systems more susceptible to a.c. corrosion
Pipe Wall thickness	Corrosion rate will result in perforation of thin wall pipe first	Pipelines with higher design safety factor sections lower risk of failure	Lower wall thickness of pipe greater risk if a.c. is identified as risk
AC pipe voltage	As low as possible less than 15V	Voltage should be monitored with data logger over at least 24 hours	Higher the voltage possibly higher risk
AC current density	<30 Am^{-2}	Current density monitored with logger over at least 24 hours	Higher current density higher risk generally
Pigable Lines	Some, a.c. defect sizes are generally small and not often excavated after pig runs	When analysing pig run data look for growth in the smaller defects that would be typical of a.c. defects	Pigging data provides good indication of any ongoing a.c. corrosion risk and defect growth
Non pigable lines	On non pigable lines excavation of coating defects may be required	Coating defect surveys required to identify coating defects then check soil resistivity and a.c. current density at defect to identify if there is a risk of corrosion	Non pigable pipelines need detailed assessment. May need to take measures to reduce pressure to conduct examination if metal loss suspected

Table 8 Parameters to consider when assessing a.c. interference risk on existing pipelines

The assessment should include in relation to a.c. corrosion;

a) The long term induced a.c. interference risk

b) Determining locations where soil resistivity is less than 25 Ohm m

c) Pipeline coating system and coating defect survey data

d) The location of power lines in relation to the pipeline route and their operating voltages

e) Measurement of a.c. voltage on pipeline system

f) Measurement of a.c. and d.c. current density through 1 cm2 coupons

g) Review intelligent pig run data

h) A.C. corrosion risk and future monitoring of the pipeline system to confirm corrosion risk status

Experience has shown that areas of low soil resistivity along a pipeline route are high risk locations for a.c. corrosion at relatively low a.c potentials. At such locations CP monitoring test facilities with a.c. coupons should be installed.

If a pipeline is routed parallel to HV power cable systems at operating voltages of 132 kV or greater then there may be an a.c. interference risk the distance between buried pipelines and overhead power cables should be established. It should be borne in mind that even at very low a.c. potentials a.c. corrosion can occur in very low soil resistivity environments.

It should be borne in mind that even at very low a.c. potentials, a.c. corrosion can occur in very low soil resistivity environments

One parameter is the a.c. pipe to soil potential. The a.c. pipe to soil potential would give an indication as to the levels of possible interference.

Routine CP monitoring checks should include a.c. voltage measurements for example If a.c voltages in excess 2 to 3V are present, and it is clear that a pipeline is routed near overhead pipelines, then that would indicate additional tests should be carried out.

The use of portable a.c. coupons may be considered to ascertain likely values of a.c. current density at certain locations. The use of a.c. coupons supplemented by the use of data loggers will assist in providing good confirmatory data to assess the level of risk.

NACE SP 21424 advises that “For existing pipelines, the a.c. corrosion evaluation process recommends an initial analysis involving factors such as pipeline history record, proximity assessments, CP data and evaluation of existing pipeline and coupon data, etc. If the initial analysis indicates that an a.c. corrosion risk is present, the initial analysis should be followed by a detailed analysis involving a.c calculations and/or a.c. measurements, evaluation of historical CP data and abnormalities, d.c. interference, inline inspection results and other existing data relevant for the analysis.

6.8 Defect Investigations

Often when in line inspection features are exposed there is not an adequate level of testing undertaken to establish the cause of any external corrosion or metal loss feature.

The tests that are carried out when exposing and examining intelligent pig features should include photographic records of any defect and measurements of pit depth and dimensions by suitably qualified inspectors. The inspection should also include details of the a.c/ d.c. current density at the defect location, the a.c. and d.c. pipe to soil potential, soil composition and resistivity checks and tests for bacterial activity.

The damaged area or area containing any metal loss feature should be cleaned prior to the initial inspection with a suitable technique e.g. water and lint cloth or 100 grit emery paper. The cleaning procedure should comply with the operator's specific requirements for such evaluations. Visual identification of the damage type, (include photographs, as appropriate) should also be included in any investigation.

Pipeline wall thickness measured at selected locations adjacent to the damage using an ultrasonic wall thickness meter with a measurement accuracy not less than 0.1mm. In the case of seamless pipe, measurements shall be made using a 20mm reference grid in a zone 60mm wide surrounding the damaged area.

Depth of any pitting using appropriate inspection tools including axial and effective length of damage.

The following tests should be carried out by appropriate trained and approved personnel: -

- Measure pipeline d.c. 'ON' and a.c. pipe to soil potential.
- Record a.c. and d.c. current density with a portable 1cm^2 coupon.
- Measure any defect dimensions with pit depth gauge and Vernier. (Measurement techniques may improve over time).
- Note date and time of tests. If possible, use a data logger to record the time dependent variation in a.c./d.c. potential and current density over a 24-hour period.
- Confirm CP status at test facilities located on each side of defect investigation including a.c. current density and voltage and gather information on CP system T/R unit operational status.

All the above tests should be carried by an experienced CP engineer

A sample of soil should be removed from around the pipeline and placed in a plastic container with an airtight seal. The soil sample should be analysed in accordance with DIN 50929-3 [23].and the soil resistivity also determined. Bacterial testing should be carried out in accordance with TM 0194[24].

The coating system and metal loss features should be examined by a suitably inspector, and adhesion tests carried out to ensure that any coating is effectively bonded to the pipeline and has not disbonded from the pipe surface. The coating film thickness should be recorded.

Once all relevant information and photographs have been recorded, sufficient coating should be removed to assist with the inspection procedure. At the initial inspection stage, minimal coating should be removed, sufficient to facilitate the inspection requirements.

6.9 Soil Resistivity

A soil resistivity survey should be carried out in accordance with ASTM G57 [25] using the Wenner 4 pin method on pipelines where there is considered to be an a.c. interference risk and the survey should be conducted along the entire pipeline route to ascertain if there are any areas of low soil resistivity e.g. salt marshes. Soil resistivities less than 25 Ohm m are high risk locations for a.c. corrosion and those less than 10 Ohm m are very high-risk locations. To assess a.c. corrosion risk the soil resistivity at the pipeline depth should be recorded and information obtained on whether any selected backfill was used.

Ideally, soil resistivity measurements should be carried out at 500m intervals along a pipeline route, but if any areas of possible low resistivity are identified by a visual inspection of the route, then resistivity measurements at more frequent intervals should be conducted.

If there are a.c. coupons installed, then high current densities will be indicative of low soil resistivity locations. For pipelines installed by the open cut technique and buried at typical pipeline depths of 1.2m in field and 1.7m at road crossings, then the soil resistance values should be determined at 0.5, 1.0, 1.5, 2.0, 2.5 and 3.0m spacings. The mean and layer resistivities should be calculated for each location

The Barnes Layer resistivity [26] at the pipeline burial depth should be used to ascertain the nature of the a.c. corrosion risk.

It should be noted that should soil resistivity data will be required to model GPR for pylons and substations close to a pipeline route. The soil resistivity data at depth will be required and soil resistivity data at varying pin spacings up to 60m may be required to complete mathematical models.

6.10 Design Requirements

If a pipeline has been identified as being at risk of a.c. interference, then an a.c. mitigation system should be designed and installed once a review of the level of interference has been evaluated. It is important that if an a.c. interference risk has been identified and a.c. corrosion is considered to be likely, then any mitigation system should be installed as soon as possible after identification of the risk, due to the high rates at which a.c. corrosion can occur.

Two approaches have been adopted in the past; one is an empirical approach where personnel experienced with a.c. interference issues on pipelines decide where to install mitigation systems e.g. zinc earthing.

The mitigation system is then designed and installed at the locations where high levels of a.c. interference have been recorded. The locations for the earthing system are normally determined by the availability of CP test facilities and where there is an existing pipe connection.

The design requirements should be based upon the guidance given in BS EN ISO 18086. Mitigation of a.c. interference would generally consist of the installation of earths connected to the pipeline at CP test facilities via suitably rated d.c. decoupling devices. The further away from the pipeline that an earth can be installed the lower will be the resistance of the earth until the electrode of a given set of geometries is at remote earth. However, land ownership issues frequently mean that the a.c. mitigation earths are installed at the edge of the pipeline wayleave particularly on retrofit mitigation systems.

The d.c. decoupling devices should be capable of carrying the prospective a.c fault current at very low voltages.

The d.c. blocking voltage would generally be -3V to +1V.

A.C. coupons should also be installed at all CP test facilities to provide the ability to monitor the a.c. interference risk along the entire pipeline. A typical test post arrangement is shown on Figure 8

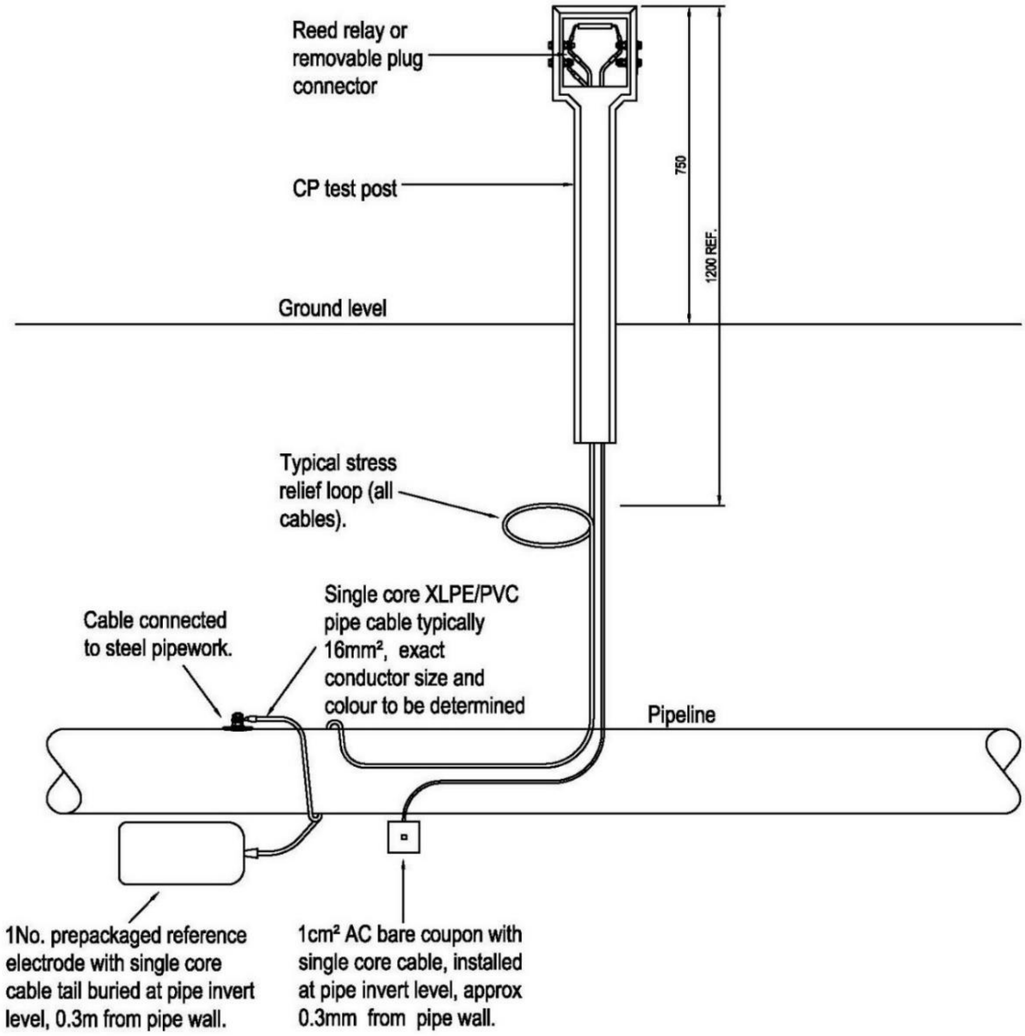


Figure 8 Typical a.c. interference monitoring test facility

The earths would typically be installed at high risk locations in terms of current density and routed along the pipeline length for a distance of approximately 150m, often longer depending upon the assessment of a.c. interference Zinc ribbons should be installed on the side of the pipeline between the power line and the pipeline to achieve the optimum effect.

The details of a typical zinc ribbon installation are given on Figure 9.

Once the earths have been installed, the a.c. interference risk should then be monitored using the a.c. coupons installed by undertaking data logging of a.c. and d.c. current density over a representative period of time.

AC corrosion monitoring standards advises that a representative period of time is 24 hours, but experience has shown that at the weekends the load on power lines decrease significantly and it is advisable therefore that monitoring is undertaken over a 7-day period to provide an accurate assessment of risk. It should be noted that the loads on the power lines would be higher during the winter months and thus data logging on high risk pipeline locations should include monitoring during winter periods.

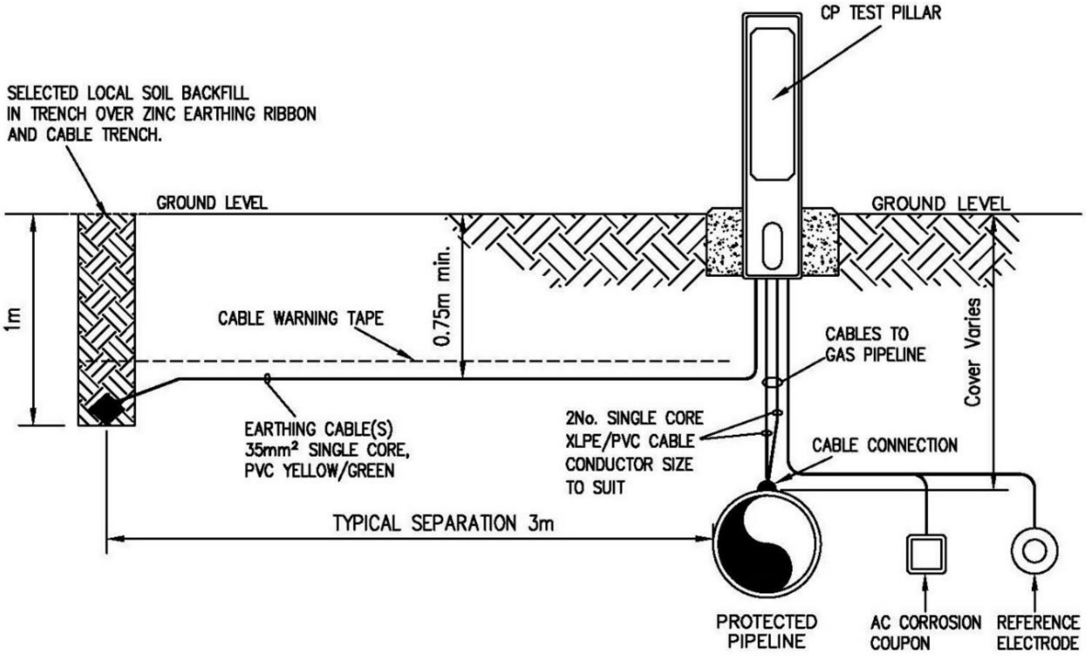


Figure 9 Typical View of Zinc ribbon installation

6.11 Over the Line Surveys

If there is a requirement to install an a.c. mitigation system on an existing pipeline. Then once a mitigation system is installed it may not be possible to undertake effective over the line surveys in the future e.g. CIP or DCVG.

This is because the decoupling devices used to d.c. isolate a.c. mitigation system earthing from the pipeline can affect over the line CIP survey data. The decouplers are capacitive devices and may discharge d.c. current to the pipeline during the 'OFF' cycle of any CIP survey.

Thus, where a PCR or SSD is employed in an a.c. mitigation system earth, there may be a limited potential shift between the 'ON' and instant 'OFF' pipe to soil potential during CIP surveys.

In the case of a PCR installation at an I/J for example, this effect, i.e. limited potential shift between the 'ON' and instant 'OFF' potential, can exist over a distance of about 2 to 3km from an I/J, based upon experience.

In the case of DCVG surveys, the earthing systems once installed will also limit the ability to perform DCVG surveys. In such situations, consideration may be given to the use of ACVG surveys. However, these too have their limitations where earthing is installed as the earthing limits the signal spread

Where the a.c. voltage on a pipeline is below safe limits i.e. less than 15V rms and provided the safety risks to survey personnel have been fully evaluated then consideration may be given to disconnection of decoupling devices over sections of a pipeline system to ensure instant OFF potentials can be recorded during a CIP/DCVG survey.

It will be essential that a CIP and DCVG survey is conducted prior to installation of any new a.c. interference mitigation system on existing pipelines to locate coating defects and identify possible a.c. corrosion locations.

This is so that operators have a record of the actual CP status of the pipeline prior to any installation of an a.c. mitigation system and all coating defects on a pipeline are identified. On a non pigable pipeline it is essential that that such surveys are performed, as an a.c. mitigation system could affect the ability to perform over the line surveys.

A DCVG survey will be required to locate coating defects that may be susceptible to a.c. interference.

Conventional DCVG surveys require a minimum potential shift of at least 250mV at the CP test facilities. However, it is recommended that a potential shift of at least 500mV is achieved at the DCVG current injection location when a DCVG survey is carried out on pipelines where there is an a.c. corrosion risk to maximise the coating defect identification. A proven switch to be able to identify the feature size that is being looked for at the depth and relative soil conditions that are being surveyed should be obtained.

It is important for all DCVG defects, no matter how small in terms of percentage IR, are accurately located and recorded prior to any a.c. mitigation system being installed.

It should be noted that in low soil resistivity environments that it may not always be possible to locate all coating defects using the DCVG technique and that some coating defects may remain undetected. This is because the DCVG survey is not as sensitive in low soil resistivity areas and small coating defects can be missed. The use of alternative defect location techniques may be considered e.g. ACVG.

In the case of existing pipelines where a new a.c. power system is to be installed close to the pipeline, consideration should be given to the effect the electromagnetic interference will create on the pipeline and the ability to undertake pipeline depth and GPS surveys in the future. It may be prudent to undertake any depth and GPS location surveys prior to any new power system energisation.

6.12 Monitoring Facilities

On pipelines where a.c. interference has been identified, test facilities should contain a.c. coupons specifically designed for use on pipelines, complete with factory connected cable of a minimum conductor size of $10mm^2$ and of a colour that will enable ease of identification as an a.c. coupon.

It is essential that a.c. coupons are identified by a completely different colour cable to any d.c. coupons to avoid confusion. A permanent reference electrode should also be installed at the same location as any coupon.

If the a.c voltage levels are expected to approach unsafe levels and the general public may be exposed to an enhanced risk then dead front CP posts, which require access with a key should be considered.

6.13 AC Mitigation System Earthing Facilities

On pipelines where a.c. interference has been identified and it is proposed to install an a.c. mitigation system, at least two cable to pipe connections should be installed at each test facility where a zinc earth will be installed.

One cable to pipe connection should be used to carry the a.c. current that will flow through any earth electrodes and the other cable to pipe connection used for potential measurement purposes and not be used to carry current. This is to avoid any potential measurement errors due to IR drop in the current carrying cable.

The minimum conductor size for the potential measurement cable should be $10mm^2$ single core and that for the pipe current carrying cable should be sufficient to carry the rated fault current for any SSD installed and should be at least $16mm^2$. On pipelines were there are just CP monitoring facilities only one pipe connection is required.

6.14 AC Mitigation System Earthing Material

Zinc ribbon anodes complying with ASTM B 418 Type 1 [27] are generally installed as part of the mitigation system. If connected to the pipeline via a decoupling device or SSD then the impedance of the earth should be sufficient to discharge a.c. current to earth and provide effective mitigation.

If earthing material other than zinc is used for earthing purposes, then consideration should be given to the effects any dissimilar metals may have on the pipeline CP system. If a decoupling device was to fail short circuit, then the earth may be connected to the pipeline and if not compatible with the pipeline CP system e.g. copper it could result in galvanic corrosion or reduction in CP levels.

Some designers specify material other than zinc to be used as an earth material e.g. copper wire in petroleum coke filled sock or copper earthing tape. The latter materials will provide a galvanic corrosion risk if directly connected to a pipeline when a decoupling device fails short circuit and pipeline operators should also consider the latter risk when selecting earthing material. Where earthing materials other than zinc are employed pipeline operators should consider enhanced monitoring to ensure any galvanic risk is monitored.

6.15 In-Line Inspection

ILI is an effective means of assessing whether a pipeline system is at risk of a.c. corrosion and whether there is an ongoing risk. Operators should review the ILI frequency based upon the a.c. corrosion risk. On pipelines that are susceptible to a.c. interference then the ILI frequency would need to be assessed and would generally be in excess of that normally adopted for a pipeline system where the a.c. interference risk is controlled or limited.

Operators should not however just rely on ILI as the only means of detecting and managing the a.c. corrosion risk as the technique does have its limitations and may not detect all a.c. corrosion features.

The accuracy and reporting of defects should be confirmed with the ILI vendor to provide operators confidence in assessment of in line inspection results in determining a.c. or general corrosion risks. If a pipeline has a known a.c. interference risk, then the ILI vendor should be informed prior to conducting any work and carrying out defect assessment studies.

The in-line inspection assessment should ascertain if there has been any growth in the smaller size defects, which are typically caused by a.c. corrosion. If there has been defect growth between successive pig runs, then this could indicate a risk of a.c. corrosion and require further investigation. The rate of defect growth may also not be linear with time as the levels of a.c interference may have changed between in line inspection intervals. The growth assessments can be inaccurate if linear defect growth is assumed and an assessment of the possible variation in a.c. interference levels between inspection should be undertaken.

6.16 Monitoring of AC Mitigation Systems

Once an a.c. monitoring and mitigation system is installed it should be monitored in accordance with the recommendations detailed in section 10.0. It has been known for some pipeline operators to install a.c. mitigation systems, but not effectively monitor their performance once installed. It is essential that once an a.c. mitigation system is installed it is monitored and maintained in accordance with this GPG and the guidance given in BS EN ISO 18086.

Proprietary remote monitoring systems are also often installed on pipelines susceptible to a.c. interference and their use is recommended. However, they should not be considered to be data loggers as they will often only record one reading a week over a 1 second period. Thy will provide functional performance and alarm checks only but will not act as data loggers.

7. AC INTERFERENCE DESIGN ON PIPELINES

7.1 Introduction

The requirements of the pipeline design standard in relation to a.c. interference risk on pipelines outlined in section 7.0 of this GPG should be followed.

The a.c. interference and monitoring design would be undertaken in conjunction with the design of the pipeline CP system. Thus, the requirements of any pipeline operators' specific standards plus those of BS EN ISO 15589-1 in relation to the CP system design and BS EN ISO 18086 for the a.c. interference design should be included in the evaluation of a.c. interference risk and design of any a.c. mitigation system. The supplementary guidance provided in this GPG should also be followed as appropriate.

The design objective is to ensure that the a.c. discharge current density at coating defects on any pipeline system is less than 30 Am^{-2} at the maximum power line operating loads that are likely to be experienced, and that the a.c. voltage on any pipeline is less than 15V rms and at a value that will ensure that the a.c discharge current density does not exceed 30 Am^{-2}. The a.c. voltage necessary to achieve the specified a.c. discharge current density is often only in the region of 1 to 5 Vrms.

The electrical safety risks associated with AC interference are detailed in BS EN 50443 and UKOPA/TBN/005

7.2 Route Selection

Consideration of the risks of a.c. interference should form an integral part of the route selection process for any new pipeline system. Wherever possible, pipelines should be routed as far as possible from overhead power lines. Thus, pipeline routes should be selected to avoid or minimize a.c. interference and an assessment of the a.c. interference risk included in the route selection process.

Where parallel runs of pipelines and power lines occur, voltage peaks may occur where there are discontinuities such as insulating joints, a junction of two or more pipelines, and at abrupt changes in power line to pipeline configuration or cable transposition locations.

Pipelines should not cross power lines at acute angles; ideally, they should cross at right angles.

7.3 Mathematical Modelling

Mathematical modelling using specialist proprietary software is required to determine the short-term interference levels on pipelines from a fault on overhead power line pylons, at a HV substation or from buried cable joint bays.

It is recommended that selected locations along a pipeline route are modelled to determine the maximum touch potential that will be experienced on the pipeline during fault conditions. If the touch potential limits exceed the required limits, then additional models may need to be undertaken.

Pipeline CP TR units may also act as earth locations along a pipeline route with fault currents discharging to earth through the CP groundbed. Modelling should be undertaken to assess the GPR within the vicinity of any CP groundbeds as part of any a.c. interference study.

However, caution should be exercised as the models created may not be accurate as a number of assumptions are made when creating the model. The soil resistivity value has a significant effect on ascertaining the risk of a.c. corrosion.

Experience has shown that whilst mathematical models can be useful, they may not always produce a mitigation system design that will be fully effective and changes to the earthing arrangement on a pipeline may be required in the future following commissioning and subsequent monitoring data.

Operators should validate any mathematical model by undertaking appropriate a.c. monitoring on a pipeline system following installation of an a.c. mitigation system or operation of any new cable system.

Mathematical modelling requires accurate information on the pipeline and power line route, details of the power system including rated and maximum loads, power cable pylon construction and details of the screen wire.

7.4 Empirical Assessments

On shorter pipeline systems and some longer ones, e.g. 20 to 30 km, a.c. interference mitigation schemes have, in the past, been designed based upon experience. This is where an experienced designer/corrosion engineer evaluates the a.c. interference risk from a knowledge of the pipeline route in relation to the power line route and determines if and where any earthing is required.

The earths would be connected to the pipeline via decoupling devices and placed at selected CP test facilities along the pipeline route.

During the commissioning phase detailed testing including data logging is then undertaken to confirm the a.c. discharge current densities are within the required limits. The empirical assessment method has proved successful in the past on UK projects. However, as the number of companies capable of offering mathematical modelling services has increased empirically designed a.c. mitigation systems are not often employed.

Empirical assessments cannot replace modelling for determination of short term a.c. interference levels. If possible, it is recommended that mathematical modelling be conducted but it should be taken into account that models may not always be accurate and often there is a difference between values determined in practice and those provided by mathematical models.

7.5 Monitoring Facilities

On pipelines where a.c. interference has been identified or is considered to be a risk the CP system monitoring facilities should contain a.c. coupons specifically designed for use on pipelines complete with factory connected cable of a minimum conductor size of 10mm^2 and of a colour that will enable ease of identification as an a.c. coupon.

On new pipeline construction projects cable connection plates rather than pin braze connections should be used. The connection plates should be fillet welded to the pipeline in accordance with an approved Weld Procedure Specification. Permanent reference electrodes should also be employed.

Where cables entering the CP monitoring facilities are not in accordance with the specified colour code for the particular company, they should be identified by proprietary cable markers.

7.6 Installation of AC Mitigation and Monitoring Systems

Once a pipeline system is installed it is important to obtain base line date on the levels of a.c. interference levels that exist on a pipeline prior to installation of any a.c. mitigation system.

However, any a.c. interference mitigation system should be connected to the pipeline as soon as possible after pipeline installation. Once a new pipeline is installed the pipeline coating will exhibit its highest impedance and gradually absorb moisture over time to reduce the coating impedance.

The coating impedance will then reduce and as the pipeline coating impedance reduces this will allow a.c. current to flow through the coating as well as at coating defects. Where the pipeline coating has a high impedance then any a.c current discharge will concentrate at exposed steel surface at coating defects.

It is important that any subsequent a.c. monitoring and mitigation system design includes for suitable test facilities to monitor a.c. interference levels.

The designer should consider whether there is a requirement for the installation of ER probes or similar devices to monitor corrosion rate as part of the design process.

Where employed, coupons should be designed so that they can be removed for subsequent laboratory examination at a later date and the date of coupon installation should be accurately recorded.

A.C. coupons if complete with factory connected cable can be excavated and removed for inspection at some time in the future and sent to a test laboratory for metallurgical examination. This will provide an indication as to whether or not a.c. corrosion has been on going and the possible extent.

Zinc ribbon should be installed so that it is located between 2 to 6m from the pipeline to minimise the earth resistance and also so that it is installed between the pipeline and the power line i.e. on the side of the pipeline facing the power cables. The zinc earth depth of burial would be typically greater than normal agricultural depth.

7.7 Remote Monitoring

On new pipelines where an a.c. interference risk has been identified, then at least one remote monitor should be employed and installed at a high risk a.c. current density location. The designer may select additional remote monitoring locations once the detailed design has been completed.

The remote monitoring device should monitor the a.c. and d.c. current densities, a.c. pipe to soil potential and d.c. pipe to soil potential.

7.8 Commissioning

It is important that following installation of an a.c. monitoring and mitigation system that all necessary pre-commissioning checks are conducted. The a.c. mitigation system should be commissioned to confirm it meets with the design specification and a fully detailed commissioning report produced.

The following tests should be performed at CP monitoring locations as part of the commissioning checks;

- a.c. pipe to soil potential
- d.c. pipe to soil potential ‘ON’/’OFF’
- a.c. current density
- d.c. current density
- Coupon instant ‘OFF’ potential

- T/R unit output levels
- A.C. current discharged to earth through any earths

All measurements should be performed with calibrated test equipment capable of measuring true rms values.

A.C. and d.c. current density readings should be taken on all a.c. coupons

The current flow through all PCRs or decoupling devices should be recorded.

Data logging should be performed to determine the time dependent variation in both a.c. and d.c. pipe to soil potential and current density.

The readings should be performed at all test facilities where the a.c. current density recorded during commissioning exceeds 10 Am^{-2}.

8. MONITORING

BS EN 15280 advises in relation to a.c. interference that "Measurement frequencies shall be in accordance with those given in BS EN 12954. As the corrosion risk is higher on a pipeline with an a.c. voltage, the operator shall pay special attention to the frequency at which measurements are taken and how the measurements are performed."

BS EN ISO 18086 provides similar guidance except it refers to the maintenance frequencies given in BS EN ISO 15589-1. Thus, as BS EN ISO 15589-1 is the latest standard in relation to CP of buried pipelines it is considered that the monitoring frequencies for pipelines subject to a.c. interference should at least be based upon the minimum requirements in BS EN ISO 15589-1 rather than BS EN 12954.

Pipeline operators should note that BS EN 12954 and BS EN ISO 15589-1 relate to cathodic protection of buried and immersed pipeline systems .BS EN 12954 was issued in 2001 when the risk of a.c. interference on pipeline systems was not widely known. BS EN ISO 15589-1 includes additional guidance but does not it is considered specifically address a.c. corrosion risks.

Failure of a CP system would generally not lead to high rates of corrosion on a pipeline unless it resulted from d.c. interference. However, failure of an a.c. corrosion mitigation system or the presence of a.c. interference on pipelines can in certain circumstances lead to corrosion rates considerably in excess of the free corrosion rate for steel in soil and an increased frequency of monitoring is recommended for pipelines affected by a.c. interference. The pipeline operator should determine the inspection frequency based upon the risks to a particular pipeline system from a.c. interference. The monitoring frequency should also be subject to periodic review during the lifetime of the pipeline system as additional sources of a.c. interference may be present and could affect the a.c. corrosion risk. Table 9 in this GPG provides guidance on recommended inspection frequencies for a.c. mitigation and monitoring systems.

A.C. interference monitoring should be combined with routine CP system monitoring to maximise resources.

It is also recommended that for pipelines where an a.c. corrosion risk has been identified that a suitable remote monitoring system should be employed. The remote monitor or monitors should be located at high risk locations to warn of alarm situations i.e. situations where there is a risk of a.c. interference and corrosion.

The use of portable data loggers to determine the time dependent variation in a.c. current and voltage at high risk locations in terms of a.c. current density and voltage should also be undertaken at periodic intervals at the same time as routine CP/ A.C. monitoring checks. The data logger measurements should typically be carried out at 1 to 10-minute intervals over a 7-day period.

If an a.c. voltage or current density reading is only taken once every 6 months at CP test facilities or on some pipeline systems once every 5 years at all CP test facilities that inspection frequency would be insufficient to identify any significant a.c. interference risks. Data logging where employed should take place over a representative period of time e.g. 7 days to provide valid data.

It is recommended that on pipelines susceptible to a.c. interference that data loggers are employed periodically at high risk locations, where the highest levels of a.c. current density have been recorded to confirm the time dependent variation in a.c. current density.

Thus, as part of any 6 monthly maintenance survey the use of one, two or more data loggers to record long term current density data would be of use to assist in an assessment of the a.c. corrosion risk

Nature of Test
Reference electrode calibration
Grounding system checks i.e. earth resistance measurements on decoupling devices
PCR and decoupling device AC current measurements
CP test station a.c. /d.c. potential measurements 'ON'/'OFF'
A.C./D.C. current density measurements at a.c./d.c. coupons
'OFF' potential measurements on pipeline system
TR system checks single source systems
TR system checks multiple source systems
Data Logging at high risk locations to confirm current densities are within prescribed limits
Remote monitoring
Calibration of remote monitoring systems

Table 9 Recommended test and inspections for pipelines with an a.c. monitoring and mitigation system installed

It is important that all measurement equipment on pipelines affected by a.c. interference has the ability to record true rms data and has sufficient levels of a.c. rejection on the d.c. measurement circuit to ensure accurate d.c. pipe to soil potentials are recorded.

The a.c. current flow through each decoupling device should be recorded at regular intervals to ensure that the device is still effective. If there is no a.c. current flow, then there may be a problem with the zinc earth that needs investigating.

8.1 Remote Monitoring

On pipelines affected by a.c. interference it is recommended that a suitable remote monitoring system is installed to record a.c. and d.c. pipe to soil potentials, a.c. current density and d.c. current density and provide an alarm indication. The remote monitors should be installed at one or more high risk a.c. interference locations along a pipeline route.

Remote monitoring devices should be calibrated at regular intervals to ensure that the data obtained is accurate. The calibration can be carried out at CP test facilities using calibrated test equipment rather than require the removal of the device and its return to the manufacturer. Remote monitor alarm settings should be set at appropriate values in terms of all parameters that are monitored, in particular a.c. current density.

Most remote monitoring devices will take only one reading or slightly more readings per week. The reading is often taken over a 1 second interval by the devices that are generally employed in the UK. If the remote monitoring interval is set at once per week then the time the measurements are taken should be one that reflects the maximum anticipated level of a.c. interference.

This would be say at 16.00 hours and not 01.00 hours in the morning when the load on a power line system would be expected to be low. It is important to confirm that any remote monitor records data at an appropriate time. The alarm levels for any remote monitoring system shall be set at values that would warn of an increased level of risk. This is both in terms of a.c. and d.c. interference.

8.2 Nature of Tests on Pipelines affected by AC Interference

The following tests should be performed at CP monitoring locations on pipelines affected by a.c. interference:

- a.c. pipe to soil potential
- d.c. pipe to soil potential
- a.c. current density
- d.c. current density at a.c. coupon
- Coupon instant 'OFF' potential
- a.c. current flow through any earths/ Polarization Cell Replacement (PCR)

All measurements should be performed with calibrated test equipment and with multimeter capable of measuring true rms values. Current density readings through all coupons and probes should be recorded.

Data logging of high risk a.c. current density locations should be conducted on a periodic basis to confirm the minimum, mean and maximum current densities at selected test facilities.

Where decoupling devices are installed and connected to earth systems to discharge a.c. current off a pipeline the a.c. and d.c. current output from the earth should be recorded together with the a.c. voltage the device operates at.

If PCR's are installed across I/F's or I/J' the current flow through the PCR should be recorded together with the a.c. voltage each side of a PCR. The corrosion rate from any electrical resistance probes on a pipeline should be noted.

The resistance of all earths installed on a pipeline to discharge a.c current should be monitored on at least a 6-monthly basis. The resistance or impedance is simply the a.c pipe to soil potential divided by the a.c current through the decoupler. A sudden increase in earth resistance would be indicative of failure of the earth. The typical resistance values of zinc earths would be in the range 1 to 5 ohms.

At locations that exhibit current densities close to or above the $30Am^{-2}$ maximum current density level data logging should be performed at representative test facilities and the data logging should take place over at least a 24-hour period and preferably a 7-day period. Data loggers should be capable of recording mean, maximum and minimum values.

In the case of a.c. interference monitoring on pipelines close to overhead power lines the frequency of monitoring or logging should be at least once every 10 minutes. In the case of data logging on pipelines close to a.c. traction systems the data logging frequency should be increased to at least once every second to identify transient events.

8.3 Data Interpretation

It is recommended that the data from any a.c. interference monitoring, and mitigation systems should be interpreted by a Level 4 BS EN ISO 15257 Certified Senior Cathodic Protection Engineer, or other competent engineer approved by the pipeline owner/operator.

The pipeline operator should however confirm that personnel employed in interpreting data, even if BS EN ISO 15257 Level 4 certified, have the required levels of experience and competency in assessment of a.c. interference risks on pipelines affected by a.c. interference.

8.4 Documents

The design of any a.c. mitigation system should comply with the relevant codes and standards identified in this GPG. It is important that following on from any maintenance survey that a fully detailed report is issued. The report should contain the monitoring data as required in this GPG, the remote monitoring system data and any data logging results.

It is important that an operations and maintenance manual is provided for any a.c. mitigation and monitoring system and that the requirements of the O and M manual are followed in relation to maintenance of a specific system.

8.5 Corrosion Rate Measurements

The current density measurements at a.c. coupons will give an indication of the level of risk of a.c. corrosion but will not give an indication of the rate of corrosion that is occurring on the pipeline system. There are devices that can be used to ascertain corrosion rate, namely ER probes or perforation probes, and these are identified in BS EN ISO 18086.

Operators would need to assess, based upon the nature of the risk, whether it is necessary to install such monitoring equipment on a pipeline. In the UK the use of perforation probes has not been adopted but ER probes with elements of surface area 1 cm^2 have been used. It is important that the ER probe has a 1cm^2 exposed surface area as this has been shown to be the coating defect surface area that exhibits the highest a.c. corrosion risk

The ER probe element thickness varies generally from 500 microns to 1000 microns. The thicker the element the lower the sensitivity in terms corrosion rate. However, if the pipeline has an ongoing a.c. interference risk and a.c. corrosion is occurring then ER probes with a thinner element will exhibit a reduced life and once the element thickness has been lost the coupon will have effectively failed.

Remote monitoring ER probes are available that can record, corrosion rate, remaining probe thickness, a.c. and d.c. current density, a.c and d.c. pipe to soil potential and coupon spread resistance. Data can be accessed remotely, and readings taken at 1 to 2-hour intervals.

The devices are solar powered which gives the ability to take readings at regular intervals. Alarm set points can also be set,

8.6 Weight Loss Coupon Examination

One method of assessing the risk or magnitude of the a.c. corrosion rate on a pipeline is to carry out laboratory examination of a coupon that has been installed to monitor a.c. current density. It is important to know the date of coupon installation and the coupon dimensions at the time of installation. The coupon can then be removed for laboratory examination to determine if any metal loss has occurred.

The technique suffers from the limitation that a linear corrosion rate would be calculated, which may not be the case in practice if a.c interference have increased during the period any coupon was installed. Thus, the estimate rate may not reflect the actual rate of corrosion that may be occurring at the time of excavation.

The local soil should be analysed in accordance with DIN 50929-3 and coupon analysis carried out in accordance with BS EN ISO 8407 [28]. It is important that the soil analysis includes measurement of soil resistivity.

The analysis of coupons will help ascertain if there has been any ongoing corrosion on the pipeline system at similar sized coating defects in that area.

The surface appearance of an a.c. coupon exposed to high levels of a.c. interference is given in Figure 10

Figure 10 Picture of a.c. coupon on which corrosion had occurred

9. REFERENCES

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Appendix A: Abbreviations

Abbreviation	Meaning
3LPE	Three Layer Polyethylene
A	Amps
AC	Alternating Current
ACVG	Alternative Current Voltage Gradient
AGI	Above Ground Installation
BS	British Standard
CIGRE	The International Council on Large Electric Systems (in French: Conseil International des Grands Réseaux Électriques, abbreviated CIGRÉ
CIP	Close Interval Potential
CP	Cathodic Protection
CSA	Canadian Standards Association
DC	Direct Current
DCVG	Direct Voltage Current Gradient
EN	European Norm
EPR	Earth Potential Rise
ER	Electrical Resistance
FBE	Fusion Bonded Epoxy
GPG	Good Practice Guide
GPR	Ground Potential Rise
HDD	Horizontal Directional Drill
HSE	Health and Safety Executive
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IEC	International Electrotechnical Commission
IEEE	Institute of Electronic and Electrical Engineers
IET	Institute of Engineering Technology
IGEM	Institute of Gas Engineers and Managers

I/F	Isolation Flange
I/J	Insulation Joint
ILI	Inline Inspection
ILIV	Inline Inspection Vehicle
INGAA	Interstate Natural Gas Association of America
ISO	International Standards Organisation
Ja.c.	a.c. discharge current density Am^{-2}
Ja.c.	d.c. current density Am^{-2}
kA	Kilo Amps
kV	Kilo Volts
LFI	Low frequency Induction
m	Metre
MAHP	Major Accident Hazard Pipeline
MFL	Magnetic Flux Leakage
mV	Millivolts
NACE	National Association of Corrosion Engineers
OHL	Overhead Line
PCM	Pipeline Current Mapper
PD	Published Document
POD	Probability of Detection
POI	Probability of Identification
PSR	Pipelines Safety Regulations
rms	Root Mean Square
SSSI	Site of Special Scientific Interest
TP	Test Point
TS	Technical Standard
V	Volts

Appendix B: Useful Information Definitions

The definitions applying to this GPG are given below:

A.C. corrosion: corrosion caused by alternating current, which originates from an external current source.

A.C. discharge device: a device blocking d.c. current but allowing the flow of a.c. current; used in the connection between a cathodically protected pipeline and an earthing electrode.

A.C. Coupon: A circular 1 cm^2 surface area representative metal sample used to quantify the extent of corrosion, current discharge off the pipeline both a.c. and d.c. or the effectiveness of applied cathodic protection.

Anode: Electrically – the positive electrode of an electrochemical cell, which emits current in the form of ionic discharge and corrodes and produces electrons. In the cathodic protection context, a device used to transmit protective current through an electrolyte to the metal to be protected (the cathode).

Bond: A piece of metal, usually in the form of rectangular strip, circular solid wire or stranded conductor, usually of copper, connecting two points on the same or on different structures to prevent any appreciable change in the potential of one point in respect of the other.

Capacitive coupling - the transfer of alternating electrical signals or energy from one segment of a circuit to the other using a capacitor

Cathode: Electrically – the negative electrode of a cell. In the cathodic protection context, it is the term given to the structure to be protected and where the cathodic reaction occurs, which in soil is reduction of dissolved oxygen in water.

Continuity bond: A bond designed and installed specifically to ensure the electrical continuity of a structure. This may be permanent or temporary, in the latter case it is used to connect two sections of a structure, which would otherwise be disconnected during the course of modification or repair.

Copper/copper sulphate reference electrode: A reference electrode consisting of copper in a saturated copper sulphate solution.

Coupon: A representative metal sample of known bare surface area used to quantify the extent of corrosion or the effectiveness of applied cathodic protection or a.c. interference.

Corrosion rate: the rate of corrosion (metal dissolution). Corrosion rate is expressed as weight loss per unit of metal area and unit of time (g/m^2 and year) or as loss of metal thickness per unit of time (µm/year = 0,001 mm/year). Weight loss can be recalculated into loss of metal thickness. The rate of localised corrosion is usually expressed as depth penetration per unit of time (µm/year).

Current density (on metal surface): current per unit metal surface area, usually expressed as Am^{-2}

DC decoupling device: A protective device that will conduct D.C. current when pre-determined threshold DC voltage levels are exceeded but will allow A.C. current to flow at all A.C. voltages.

Depolarisation: The change in the potential of the cathode as a result of cessation of current flow and is a time dependent process.

Direct current voltage gradient (DCVG): An above ground surveying system that is used for the location and sizing of coating defects on buried pipelines. During DCVG surveys, the cathodic protection current is pulsed. A sensitive milli-voltmeter and two copper-copper sulphate reference electrodes, placed about one metre apart by the surveyor, are typically used for surveying purposes. Thus, the potential gradient associated with coating defects can be identified and assessed to provide a qualitative assessment of defect size.

Drain point: The location of the negative cable connection to the protected structure through which the protective current returns to its source.

Earthing resistance: the electrical resistance between a metal surface (e.g. the steel surface in a coating holiday on a buried pipe, or an earthing electrode or an a.c. power line pole foundation) a remote earth.

Earth Potential Rise (EPR): the increased potential of an a.c. tower earthing point and the surrounding soil due to earth currents, especially the high fault current at a phase-to-earth fault in an a.c. power line tower. The potential rise may also be caused by a lightning strike to the tower, and which may result in a phase-to-earth fault. The EPR is a function of the a.c. tower earthing and the soil resistivity.

Free corrosion potential (natural potential): The potential of a corroding surface in an electrolyte relative to a reference electrode.

Groundbed: A system of buried or submerged electrodes connected to the positive terminal of an independent source of direct current, in order to lead to earth, the current used for the cathodic protection of a buried or immersed metallic structure.

Ground potential rise (GPR): The maximum electrical potential that a substation grounding grid may attain relative to a distant grounding point assumed to be at the potential of remote earth. This voltage, GPR, is equal to the maximum grid current times the grid resistance.

NOTE—Under normal conditions, the grounded electrical equipment operates at near zero ground potential. That is, the potential of a grounded neutral conductor is nearly identical to the potential of remote earth. During a ground fault the portion of fault current that is conducted by a substation grounding grid into the earth causes the rise of the grid potential with respect to remote earth.

Holiday: A hole, break or other discontinuity in the coating on a pipeline, which causes the pipe surface to be exposed.

IR error: This is the error contained within the pipeline potential recorded at ground level remote from the actual pipe surface. This error is caused by the flow of cathodic protection currents and the resistance of the soil and coating.

Impressed current: The current supplied by a rectifier or other direct-current source, (specifically excluding a galvanic anode), to a protected structure in order to attain the necessary cathodic protection.

Inductive coupling the coupling between two electric circuits through inductances linked by a common changing magnetic field.

Insulated flange: A flanged joint between adjacent lengths of pipe in which the nuts and bolts are electrically insulated from one or both of the flanges by the use of insulating sleeves and the jointing gasket is non-conducting, so that there is an electrical discontinuity in the pipeline at that point.

Insulated joint: A manufactured joint or coupling between two lengths of pipe, inserted in order to provide electrical discontinuity between them.

Instant 'OFF' potential: The structure to electrolyte potential that is obtained immediately after the disconnection of the structure under CP from the CP current source. This is sometimes referred to as the polarised potential and is the true pipe to soil potential excluding any voltage created by current flowing through the soil and pipeline coating.

Interaction test: A test to determine the severity of corrosion interaction between two buried or immersed structures.

Interference phenomenon resulting from conductive, capacitive, inductive coupling between systems, and which can cause malfunction, dangerous voltages, damage, etc.

interference voltage - voltage caused on the interfered system by the conductive, inductive and capacitive coupling with the nearby interfering system between a given point and the earth or across an insulating joint.

Natural potential: See free corrosion potential.

Permanent reference electrode: A permanently buried or immersed reference electrode designed for long life and installed close to the structure to enable the structure potential to be measured.

Polarisation: An effect of electrolysis, which occurs, on either the anode or the cathode of a cell when gas or chemical products form on the electrode. The polarisation effect is to increase the circuit resistance of the cell thus reducing the current for a given voltage.

Polarised potential: The potential between a reference electrode and the pipeline, which exists immediately after an interruption of the CP current, (i.e. instant off potential).

Reference electrode: A device used to compare potentials at various locations by providing a standard for potential measurement. Electrodes may be made of zinc, copper in a saturated copper sulphate solution or silver and silver chloride in a chloride ion solution of known concentration.

Sacrificial anode: An anode that relies on a natural potential difference as a source of power. The 'driving voltage' can be found from the electrochemical series. Metals generally used as galvanic

Stray current: Incidental current picked up by a structure from adjoining foreign sources.

Soil resistivity: specific resistance of a soil to carry electric current. Soil resistivity is expressed in Ω m (earlier in Ω cm). The lower the soil resistivity, the easier it is for electric current to flow through the soil. Fine-grained soils with water holding capacity (clay, silt, peat etc.) usually have low resistivity, whilst coarse grained and water draining soils (sand, gravel, till etc.) usually have a high resistivity. The water and salt content of the soil have a large influence on the resistivity. A high water and a high salt content results in a lower resistivity. Road de-icing salt, which is drained through the soil, lowers the soil resistivity.

Spread resistance: ohmic resistance through a coating defect to earth or from the exposed metallic surface of a coupon to earth.

Note: This is the resistance which controls the d.c. or a.c. current through a coating defect or an exposed metallic surface of a coupon for a given d.c. or a.c. voltage.

Sulphate-reducing bacteria (SRB): These act as depolarisation agents in the soil around the structure and are harmful to the cathodic protection effect. They achieve this by reducing sulphate ions to sulphide and consuming the hydrogen of the polarisation film. They occur in anaerobic soil conditions and can result in relatively high rates of corrosion.

Telluric effect: A natural phenomena caused by solar activity deforming the earth’s magnetic field causing low frequency current to flow in the general mass of earth. Telluric currents can result in stray current interference on long pipelines.

Touch voltage: The potential difference between the ground potential rise (GPR) and the surface potential at the point where a person is standing while at the same time having a hand in contact with a grounded structure.

Appendix C: Typical Questionnaire Pipeline Operator to Power Line Operator

AC INTERFERENCE QUESTIONNAIRE

Item	Question	Response
1.0	Power System Operator and Contact details	
2.0	Operating Voltage and tolerance in voltage and frequency	
3.0	Power circuit designation and name	
4.0	Earthing impedance at substation	
5.0	Tower construction details	
6.0	Tower span	
7.0	Number of phases	
8.0	Number of circuits	
9.0	Average Height of Conductor 1 from ground	
10.0	Average Horizontal Distance of Conductor 1 from ground	
11.0	Phase angle of conductor 1	
12.0	Average Height of Conductor 2 from ground	
13.0	Average Horizontal Distance of Conductor 2 from ground	
14.0	Phase angle of conductor 2	
15.0	Average Height of Conductor 3 from ground	
16.0	Average Horizontal Distance of Conductor 3 from ground	
17.0	Phase angle of conductor 3	
18.0	Conductor resistance	
19.0	Earth/shield wire resistance and conductor size	
20.0	Average tower footing resistance	

Item	Question	Response
21.0	Fault clearance time msec	
22.0	Fault level substation	
23.0	Fault current pylons	
24.0	Peak Loading (Amps)	
25.0	Normal Operating Load (Amps)	
26.0	Designed Rated Load (Amps)	
27.0	Emergency Loading (Amps)	
28.0	Emergency Loading Time (Amps)	
29.0	Operating Power Loading MVA	
30.0	Transposition Locations	
31.0	Phase arrangement on Pylons	

Appendix D: Typical Questionnaire Power Line Operator to Pipeline Operator

Pipeline Questionnaire

Item	Question	Pipeline Operator Response
1.0	Pipeline operator, address and contact details	
2.0	Pipeline systems within vicinity of new power lines	
3.0	Pipeline system details, pressure, wall thickness, diameter	
4.0	steel grade	
5.0	Pipeline length	
6.0	Pipeline route drawings	
7.0	CP system type sacrificial or impressed current	
8.0	Pipeline CP system drawings and test post locations	
9.0	CP system TR unit and groundbed location’s	
10.0	CP system operating levels	
11.0	Coating thickness and type	
12.0	Pipeline Engineering Line Diagram	
13.0	Pipeline design code	
14.0	Are there any inter pipeline bonds	
15.0	Is any a.c mitigation system already installed	
16.0	Coating impedance to be considered for AC system design purposes Ohms m^2	
17.0	Isolation joint locations and whether buried or above ground	
18.0	Details of any surge protection already installed	
19.0	Details of any existing ILI features	

Item	Question	Pipeline Operator Response
20.0	Safe working requirements for work in vicinity of pipeline	
21.0	Details of any over the line surveys	
22.0	Details of any existing a.c interference on pipelines or power lines in vicinity	
23.0	Soil resistivity data	
24.0	CP test post design and method of cable to pipe connection	
25.0	Pipeline burial depth	

Appendix E: AC Corrosion on Pipelines UK Experience

Although it had been demonstrated in the 1960's under laboratory conditions that a.c. current can cause corrosion of cathodically protected pipelines, it was not recognized until comparatively recently that a.c. corrosion of cathodically protected pipelines can and does occur. The phenomenon of "alternating current corrosion," or "A.C. corrosion," has been investigated in detail since the observation of the first corrosion damage in Europe by induced a.c. currents, which resulted in a.c. corrosion on cathodically protected pipelines in 1988 [29, 30].

Ellis [31] reported the first incident of a.c. corrosion in the UK during a UKOPA conference in 1999. The HSE in the UK then advised all pipeline operators to be aware of the a.c. corrosion risk and then take steps to identify pipeline systems at risk of a.c. interference and take appropriate action. The latter guidance it is considered still applies today.

A.C. corrosion occurs at small coating holidays on well coated pipelines where the pipeline suffers from induced a.c. voltages. It can occur on pipelines that have effective levels of CP.

Pipelines which parallel overhead or buried power lines and also a.c. traction systems can have an a.c. voltage and current induced on them. The a.c. current flow in the power line conductors produces an alternating magnetic field and that can result in low frequency induction on buried pipelines.

Thus, an a.c. voltage and current can be induced in an adjacent structure within that magnetic field and a current may flow in that structure. The magnitude of the induced voltage depends on a number of factors including:

Configuration of the power line and pipeline e.g. length of parallelism and separation from the pipeline

- Separation distance between each of the phase conductors and the pipeline
- Current load on the power line
- Power circuit operating voltage
- Imbalance between phases
- Impedance of the pipeline coating.
- Soil resistivity

In general terms the greater the current load on the power line, the longer the parallelism, the closer the proximity, the better the coating quality on the pipeline, the more likely it is that significant a.c. voltages and current will be induced on a pipeline.

For many years, the general view in the corrosion industry has been that alternating current causes approximately 1% of the corrosion of the equivalent direct current.

A.C. corrosion can result in relatively high rates of corrosion on cathodically protected pipelines, such that even if the protection criteria to ensure immunity from corrosion detailed in BS EN 12954 are obtained on the pipeline, if the pipeline is exposed to an a.c. corrosion risk, then corrosion may still occur and often at rates considerably in excess of the free corrosion rate for steel in soil.

The high coating quality pipelines namely fusion bonded epoxy (FBE) and 3-layer polyethylene and polypropylene pipelines are particularly susceptible to a.c. corrosion. However, a.c. corrosion can also occur on the older coal tar enamel coated pipelines. The a.c. current densities recorded on the pipeline were in the region of 40 to 160 $Am^{-2.}$ The pipeline was installed in 1992 and a 40% wall thickness loss was identified in a pig run carried out in 1996.

The pipeline diameter was 10" and the product transported was dense phase ethylene. The pipeline design pressure was 99.3 bar. The pipe minimum wall thickness was 5.65 mm for standard wall pipe and a 40% loss of wall had occurred over a 7-year period at one location, which would equate to corrosion rate of 0.57 mm per year.

A subsequent pig run was carried out in 1999 and additional defects were identified, where the metal loss was 30% of wall thickness, which would equate to a corrosion rate of 0.24 mm per year.

The soil resistivities were low at the defect location with Ellis quoting values of 1,500 Ohm cm (15 Ohm m) at 1m depth and 500 to 800-Ohm cm, (5 to 8 Ohm m) at 1.5 metres. At the time the pig runs took place on the pipeline there was no a.c. mitigation system installed.

An a.c. mitigation system on the pipeline was installed after 1999 to discharge the a.c. current induced on the pipeline to earth. Following the 1999 incident another incident of a.c. corrosion was reported on a gas pipeline in the UK in 2002. The pipeline was a 16" diameter 75 barg high pressure natural gas pipeline to a power station.

Movely [32] discussed the pipeline and another a.c. corrosion investigation on a 16" diameter pipeline to a gas fired power station in the UK from a regulatory authority' perspective. The gas fired power station incident occurred in 2002 and there was a total of 93 external corrosion defects identified on an in-line inspection conducted in December 2002 following pipeline installation In September to December 1999.

Lydon [33] provided additional details on the a.c. corrosion investigation on the pipeline to the gas fired power station described in Movely's paper. Lydon advised that the pig run data showed that the defects were concentrated within two areas. The first set of 33 defects were concentrated within an environmentally sensitive low soil resistivity location referred to as an SSSI. The second set of 60 external metal loss defects was concentrated in a clay soil that ran parallel to a main road. These defects were concentrated between chainage 4371m to 5891m.

The following corrosion rates were reported and are given on Table 10

Defect Locations	Corrosion Rate mm per year		
	Mean Rate	Minimum Rate	Maximum Rate
SSSI Area	0.7	0.17	1.2
Salt Marsh Area	0.41	0.17	0.81

Table 10 A.C. corrosion rates 16" gas pipeline UK 2002

The resistivity at the SSSI site was very low, in the region of 1-ohm m, whilst that in the salt marsh area was between 8 to 10 ohm m.

The pipeline system was also subjected to d.c. stray current interference for a short period of time shortly after construction and it is known that where both a.c. and d.c. interference occur on a pipeline system then this can result in higher rates of a.c. corrosion. Nielsen [13] has published data for corrosion rates on pipelines susceptible to both a.c. and d.c. interference and higher rates of corrosion are experienced.

There have since the latter incidents been other reported a.c. corrosion incidents in the UK on both FBE and coal tar enamel coated gas pipelines.

Lydon reported the highest a.c. corrosion rate in the UK on an intermediate pressure gas pipeline in the South of England in 2006, where through wall corrosion occurred and the corrosion rate was in the region of 2.42mm per year see Figure 11 A.C. corrosion defect current density 450 to 600 Am^{-2} 8" intermediate pressure < 7bar gas main.

Figure 11 A.C. corrosion defect current density 450 to 600 Am^{-2} 8" intermediate pressure < 7bar gas main

The increased corrosion rates on a pipeline without an a.c. interference mitigation system due to a.c. interference will vary from about 0.1 to 2.5mm per year based upon UK experience.

A.C. corrosion in the UK is not just restricted to FBE or 3LPE coating systems. Eyre [34] in 2015 reported two case studies involving a.c. corrosion on coal tar enamel coated pipelines.

One case resulted in through wall corrosion on a 7.7mm thick 8" diameter coal tar enamel coated aviation fuel line.

The 2006 ILI had indicated a metal loss of 49% at a defect location and through wall failure occurred in 2015 this equated to a corrosion rate of 0.42mm per year.

The a.c. voltage and soil resistivity were low at the defect site. The voltage was in the region of 1.75V rms and the soil resistivity 10 Ohm m. The leak site was at a CP drain point not too far from where a 400kV power line deviated from the pipeline route. The average a.c. current density at the defect location was quoted as $43Am^{-2}$.

The second case Eyre reported was on a refined product pipeline where 49% loss of wall thickness occurred. The a.c. voltage varied between 1 to 6.0V at the defect site and the soil resistivity was very low at 1 ohm m. A.C. current densities in the region of 5 to 380 Am^{-2} were recorded at the defect location, which was where the pipeline route crossed a 400kV overhead power line at an acute angle.

The corrosion rate from a.c. interference will be dependent upon a number of factors. These are most notably, the a.c. current density, the soil resistivity and soil composition, the pipeline coating system, the pipeline route relationship to the power line system, particularly the separation between the pipeline and the power line, the pipeline crossing angle and the current loading on the pipeline system.

A.C. interference primarily occurs on pipelines that are routed in parallel with power lines operating at voltages of 66kV and above.

Generally, the higher the a.c. discharge current density the higher the corrosion rate. However, the corrosion rate at different current densities does vary and is dependent upon a number of different factors.

The a.c. corrosion defects identified on the both pipelines discussed in Movely's paper are understood to have been arrested by the installation of an a.c. corrosion mitigation system. However, for pipelines considered to be at risk of a.c. interference it is prudent to have an increased ILI frequency until it can be confirmed that the a.c. corrosion process has been arrested by any mitigation system.

In the UK with corrosion rates up to 2.5mm per year being reported on pipelines without any mitigation system it is essential that the a.c. corrosion risk is controlled to ensure pipeline integrity and safety.

Whilst FBE pipelines are more susceptible to a.c. corrosion it can also occur on coal tar enamel and two-layer polyethylene coatings.

In the case of modern pipeline coating systems, the coating quality is high, and the high coating impedance means that the a.c. current flow through the coating is relatively low, with most current concentrating on small defects in the coating system. Thus, it is the small surface area coating defects on a pipeline that are the high-risk locations for a.c. corrosion.

The UK experience has shown that where the soil resistivity is very low, a.c discharge current densities can be very high and there is a high risk of a.c. corrosion at relatively low a.c. voltages.

Soil resistivity and composition plays an important role in the a.c. corrosion rates and likely risks.

Management of Pipelines Affected by AC Interference – Good Practice Guide (GPG) General Information

By

[redacted]

To

UKOPA May 16th 2018

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Presentation

- This presentation has been produced to provide UKOPA with information on the present status of the Good Practice Guide (GPG) for the Management of AC Interference on Pipelines.
- I intend to provide a brief summary of the topics that the GPG will address and the approximate timescale for completing the document

Background

- I was asked by UKOPA to produce a GPG on the Management of AC Interference on Pipelines
- I have been involved in a few investigations into AC corrosion on pipelines in the past
- I was also involved in the preparation of BS EN 15280 *Evaluation of a.c. corrosion likelihood of buried pipelines applicable to cathodically protected pipelines* as one of the UK representatives
- About 30 years experience in the pipeline industry primarily on CP and related issues

Aim

- The aim of the Good Practice Guide (GPG) is to provide practical guidance on AC interference both from an electrical safety perspective and the management of AC corrosion risk.
- There is guidance given in BS EN 50443 on electrical safety but it is not ideal in certain respects and differs from international best practice advice and guidance in current UK legislation
- The GPG aims to provide some clarity particularly on touch potential values that operators in the UK should consider for pipelines.
- Suggested monitoring and maintenance frequencies for AC interference monitoring and mitigation systems are provided in the GPG

Aim 2

- BS EN 15280 specifies the protection criteria. However, the GPG expands on the criteria and discusses situations based upon experience where the alternative criteria given in BS EN 15280 may not be valid and have limitations.
- The guidance given in BS EN 15280 has been expanded upon to give practical information on AC corrosion mitigation and monitoring
- The GPG aims to provide identify issues that pipeline operators need to consider when installing an AC corrosion monitoring and mitigation system on both new and existing pipelines.

Status

- Draft of document sent to UKOPA in January 2018
- Actual document was considered to be more detailed than had been anticipated by the PWG.
- The document has now been revised and sent to Simon Joyce for comment
- Once comments have been received and reviewed the document will then be revised and submitted for Peer review
- Peer review will be conducted by John Dyson
- If document back by end or May looking at completion by August 2018


Contents of GPG

- 1.0 Introduction to GPG
- 2.0 Described different methods of AC interference e.g. coupling types and consequences of AC interference i.e personnel safety and AC corrosion
- 3.0 Include a review of case histories on AC corrosion failures/incidents in the UK and provide guidance on typical corrosion AC corrosion rates that have been experienced

Contents of GPG- 2

- 1,0 Provide guidance on situations that lead to high AC corrosion rates on cathodically protected pipelines.
- 2.0 Identify high risk factors e.g soil resistivity, soil composition, situations that can lead to high levels of AC interference e.g acute crossing angles, out of balance loads etc.
- Requirements for remote monitoring and limitations of remote monitoring systems in realtion to AC interference

Contents - 3

- Protection criteria for AC corrosion mitigation are discussed and reasons why AC current density limits rather than AC voltage criteria have been selected.
- Some operators and CP companies still use voltage limits given in now withdrawn DD CEN/TS 15280. AC voltage limits were withdrawn because AC corrosion failures had occurred at voltages less than the values specified.
- Applicability of different protection criteria to mitigate AC interference
- Use of alternative protection criteria and methods of assessing AC corrosion

Contents - 4

- Section included on electrical safety.
- This will include construction and operational electrical safety risks
- It will include a lot of the information included in the Electrical Safety presentation to follow but a more detailed written text will be provided
- The requirements and processes for assessment of AC interference risk and mitigation on both new and existing pipelines will be outlined

Contents - 5

- Provide guidance on AC interference in specific situations

    - **Overhead pipeline crossings of railway lines**
    - **Pipeline to pylon separation**
    - **Routing of pipelines close to substations**
    - **Use of PCRs and surge protection devices**
    - **Microwave transmission towers and pipelines**
    - **AC interference from rail traction systems**
    - **Power cable crossing of above ground pipelines**
    - **Issues associated with routing new cables close to existing pipelines**

Contents - 6

- Guidance on AC interference monitoring and maintenance frequencies
- Nature of tests to be conducted
- Advice on how to conduct examinations on ILI features to determine the level of AC interference on a pipeline system.
- Indicate tests required so that operators can confirm whether AC corrosion is a possible cause of external corrosion defects

Supplementary Information

- Provide guidance on mitigation of AC interference during construction e.g earthing of pipework , inline current flow and mitigation of static electricity risk
- Discuss affect decoupling devices across I/Js can have on AGI earthing systems and spark risk.
- Increased incendive ignition risk from AC interference at I/Js..
- Provide guidance to powerline operators on effects increase in power line loading can have on buried utilities
- Guidance on use of surge protection and insulating devices.
- Identify maximum coating withstand and insulation joint voltage limits.
- Identify specific requirements for surge protection on insulated flanges

Technical Publications

- There are a number of published documents in the literature on AC interference
- The literature search conducted as part of the preparation of AC GPG will be given to UKOPA
- Nikki Barker is to include these technical papers in the members gallery.
- A detailed list of relevant standards and legislation will be provided

Appendices

- The Appendices to the document will include a complete list of references and relevant standards.
- Details of questionnaires that pipeline operators should send to powerline operators to gain details of interfering powerlines and details on pipeline system that powerline operators will require to undertake any model.
- List of useful definitions and abbreviations

Anything Else

- Is there anything that UKOPA want covered but has not been identified as being covered in the GPG?
- Are there any issues members wish to address in the GPG?

September 2025

Electricity Transmission Design Principles

Consultation on Principles

NESO
National Energy System Operator

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Executive Summary

Executive Summary

In 2023 the Electricity Networks Commissioner proposed recommendations on how to accelerate the deployment of strategic electricity transmission infrastructure in Great Britain. The UK Government adopted these recommendations which now form the basis of the Transmission Acceleration Action Plan (TAAP). The TAAP sets out 43 recommendations, which collectively seek to reduce build time of electricity transmission network infrastructure from 14 to 7 years.

Recommendation "RD1" of the TAAP sets out that Electricity Transmission Design Principles ("the Principles") be created to provide greater clarity on the type of asset to be used in different environments.

The Principles sit in the context of other planning reforms by the UK Government to speed up and streamline the delivery of new critical infrastructure. This includes updating the National Policy Statements for energy infrastructure, which at the time of this consultation set out that developers of electricity transmission infrastructure should have regard to the Principles.

The Principles consider strategic, network planning and project development needs and will apply to new transmission infrastructure projects identified from January 2026. They have been developed by the National Energy System Operator (NESO) alongside other Working Group members and are now in public consultation. Further information on the Working Group is available in Section 3 of this document.

The Consultation

We invite all parties with experience of, and an interest in, electricity transmission projects to respond to this consultation with consideration to the following questions.

Key questions

1. Do you agree the Principles are written in a clear and accessible manner?
2. Given the context of the mission statement, are there any guidelines for transmission design that you think are missing?
3. Which of the Principles do you support, and which do you disagree with and why?
4. Do the Principles promote transparency in decision-making about new transmission projects?
5. Are the Principles realistic and actionable for designers and users?

1. Introduction

Purpose of this consultation

Consultation objectives

Use of Artificial Intelligence

Introduction

Purpose of this consultation

The National Energy System Operator (NESO) is responsible for coordinating the implementation of the strategic development plans for Great Britain's electricity transmission network. NESO and the three Transmission Owners (TOs)[1] have a statutory obligation to develop plans that consider network efficiency and consumer value for money whilst balancing the impact on the environment and local communities.

It is widely recognised within the UK Government and the electricity transmission industry of Great Britain, that to meet the Government's net zero targets and enable economic growth, the delivery of electricity transmission infrastructure needs to be significantly accelerated. Part of the acceleration strategy declared by the UK Government's Transmission Acceleration Action Plan (TAAP)[2] is to clearly communicate to potential transmission development stakeholders the type of transmission infrastructure they can expect to be installed in different types of terrain.

Of course, no single document can cover every eventuality for every infrastructure project, so these Principles do not represent 'policy' or 'rules'; rather, they aim to provide firm general (non-project specific) design guidance, with the expectation that justification will be provided for significant deviations. To achieve this, we were asked by the Department for Energy Security and Net Zero (DESNZ) to create, own and manage a set of 'Electricity Transmission Design Principles' (ETDP) that will be held in a publicly available living document, updated from time to time in a process of review and continuous improvement as described in Section 8, Next Steps.

Planning, consenting, and building new transmission infrastructure projects can take significant time, currently up to 14 years in some cases. The Electricity Transmission Design Principles aim to streamline the process by reviewing and agreeing some of the general principles associated with transmission design up front before specific projects come into development. This will allow discussions to focus on the unique aspects of project development and reduce the need for repeated discussions on design aspects.

We are keen to understand your views so that you can understand, comment, and inform the development of the final version that will guide transmission infrastructure design across

[1] The Great Britain Transmission Owners are National Grid Electricity Transmission, Scottish Hydro Electric Transmission Ltd, and SP Energy Networks.

[2] Transmission Acceleration Action Plan, Department for Energy Security and Net Zero, November 2023

Great Britain. Once the consultation and final redrafting is complete, the Principles are due to be given force in England and Wales by the UK Government's National Policy Statements (NPS) for the development of nationally significant infrastructure, in particular, NPS EN-5 – 'Electricity Networks Infrastructure'. The Scottish Government have also been a consultee, and the intention from the TAAP is that these Principles complement Scotland's National Planning Framework.

In addition, the Principles will become embedded into our strategic energy network planning processes through the Centralised Strategic Network Plan (CSNP)[3], which will use an evidence led approach to identify, develop, appraise options and recommend reinforcements both offshore and onshore. Specifically, the Strategic Principles and Network Planning Principles will apply to options submitted into the CSNP by the TOs and other parties. Meanwhile, the Project Development Principles will primarily be used following a CSNP recommendation, as projects go through detailed design and consenting.

We are pleased to invite your feedback on the proposed Principles based on the key questions raised in the Executive Summary and included here for ease of reference. The following pages detail the Principles and the ways in which you can comment on them.

Consultation objectives

This consultation aims to:

1. Gather comprehensive stakeholder perspectives on whether the proposed Principles effectively address the mission statement presented at the end of Section 2 of this consultation document.
2. Validate, and improve the clarity and applicability of the drafted Principles to ensure they provide practical, implementable guidance for all parties involved in transmission infrastructure development.
3. Identify and address potential gaps in the Principles that may not have been fully considered during the initial development phase.

Use of Artificial Intelligence

This consultation seeks to engage a broad range of stakeholders to ensure that a diversity of views and opinions are considered during its development. Artificial Intelligence (AI) will be employed to support summarising of the data and transforming it into actionable insights, facilitating a more efficient and comprehensive understanding of stakeholder perspectives across various sectors of society. All feedback received from

[3] Centralised Strategic Network Plan Draft Methodology
neso.energy/document/363521/download

stakeholders on the Principles will be read and reviewed by a human in both its raw and summarised form.

AI's ability to handle diverse data sources and formats enhances our capacity to engage with a wide range of stakeholders. AI can process large volumes of feedback quickly and accurately, ensuring that no valuable insights are overlooked. Additionally, AI can identify patterns and trends within the feedback that might not be immediately apparent to human reviewers alone.

AI will not be used to make decisions autonomously, but to serve as a tool to enhance, rather than replace, human judgement and support decision making. AI will help to highlight important issues and common themes, allowing us to include stakeholder feedback more effectively and proactively. This comprehensive approach ensures that stakeholder input into the Principles is informed by a broad spectrum of perspectives, allowing us to respond in a timely and appropriate manner.

We will regularly review our use of AI in interpreting stakeholder responses, and we will be able to attribute any stakeholder insight identified by AI to its original source.

We acknowledge the potential for biases in AI platforms. We will incorporate bias mitigation strategies into our AI planning processes. This proactive approach will help us ensure that the actionable insights our AI systems provide are fair, unbiased and reflective of the diverse range of stakeholders' views.

Additionally, we recognise our responsibility to maintain transparency and due diligence in all our activities; AI-related activities included. Our AI use will strictly adhere to NESO’s relevant policies, including AI, data management, data privacy, data classification and data sharing. These policies ensure that our AI practices are aligned with our commitment to ethical standards and regulatory compliance.

2. Concept of the Electricity Transmission Design Principles

Background and Approach

Problem Statement

Projects in scope

Scope interaction

Technologies in scope

Mission Statement

Concept of the ETDP

Background and Approach

Recommendation 'RD1' of the UK Government's Transmission Acceleration Action Plan (TAAP) states that:

"Electricity Transmission Design Principles should be created to provide greater clarity on the type of asset to be used in different environments."

To achieve RD1, we intend that the Principles draw together design considerations from key policy, industry guidance and professional experience, recording, clarifying and updating these in the process to ensure they are fit for purpose. In particular, the draft that we present in this consultation has been strongly guided by:

- The legislative framework for transmission developers, in particular their Transmission Licence conditions and the National Policy Statement EN-5 – 'Electricity Networks National Policy Statement' as well as the National Planning Framework 4 in Scotland.
- The Holford and Horlock Rules, which have provided designers with guidance for many years on overhead lines and substations, respectively, and which form part of current EN-5 Policy.
- Practical professional experience of transmission design provided by The National Energy System Operator (NESO) and the three Transmission Owners (TOs).

The first issue of the Principles is intended to operate alongside the Holford and Horlock Rules –two longstanding sets of rules that are well known in transmission design. As the Principles mature and increasingly take effect, consideration will be given as to whether the Holford and Horlock Rules will be subsumed by the Principles. Equally, as the Principles gain traction more broadly, national policy makers may wish to move some of the transmission design details to the Principles and reference the Principles as the single source for those details.

To support the development of the Principles, we convened a Working Group to ensure alignment between project developers and policy makers. We have been working with the Transmission Owners, the Department for Energy Security and Net Zero (DESNZ), The Office of Gas and Electricity Markets (Ofgem), the Welsh and Scottish governments as well as the Planning Inspectorate, since June 2024 to scope and develop the Principles. This consultation document represents a refined draft of the NESO-led Working Group.

During the development process, we also sought input from external stakeholders including the Landscape Institute, the National Infrastructure and Service Transformation Authority (NISTA, formerly the National Infrastructure Commission), RenewableUK, the Energy Systems Catapult, and the Electricity Networks Commissioner himself. By engaging in this way, we have endeavoured to ensure that, while the Principles address the design points in question, they also reflect a broad range of perspectives from across the energy sector, affected communities and environmental interests.

To test the practical application of the Principles, TOs undertook a testing exercise. This involved applying the Principles to recently consented projects and assessing what impact they would have if applied from project inception. The feedback from this exercise usefully informed Principle development, particularly with respect to the use of terminology or descriptions that unnecessarily and unintentionally limited the scope of a Principle's application.

Problem Statement

Early in the drafting process we developed the following Problem Statement, with input from the Working Group, to capture the key challenges that the Principles are intended to address:

- Articulate unambiguous guidelines on transmission technology choices.
- Are sensitive to and strive to mitigate the impact of transmission infrastructure on the environment, landscape, and communities.
- The National Policy Statements (England and Wales) and National Planning Framework 4 (Scotland) set out rules and guidance relevant to the design of transmission infrastructure which, along with the Holford and Horlock Rules, can be open to interpretation by different parties.
- There is lack of clarity among stakeholders on which aspects of a proposed design can be changed and what impact mitigations can be included to improve community acceptance.
- During the regulatory approval process, measures taken to gain community acceptance can be challenged. As a result, redesign of the route and reapplication for planning approval may be required, or additional funding sourced in a timely manner to avoid further delay.
- Public enquiries relating to proposed transmission investments encounter repeat questions on the need for a particular type of transmission technology employed for a given route or site.
- Many transmission design decisions that impact communities are made ahead of any community consultation, and TOs find that, where justification for these is not effectively communicated to impacted stakeholders, additional queries can be triggered at later stages of the planning process.

Projects and Technologies in scope

Following publication of the Principles, all new electricity transmission projects in Great Britain, identified from January 2026, will be expected to have regard to the Principles. This will include, but is not limited to, network reinforcement options entering network planning processes from the first iteration of the Centralised Strategic Network Plan (CSNP)[4]. Designers will not be expected to apply the Principles retrospectively to projects currently in development.

The Principles apply, as appropriate, to all transmission projects where new infrastructure is to be installed, whether new-build or system upgrade, and whether or not the project is expecting to utilise or extend existing transmission corridors or substation sites. The aim is to ensure that a series of relatively minor system upgrades, if left outside the scope of the Principles', does not undermine their effectiveness in supporting efficient and economical transmission infrastructure that also considers community and environmental impacts.

The Principles will apply to onshore and offshore transmission infrastructure operating at voltages of 275 kV and above (132 kV and above in Scotland).

[4] Centralised Strategic Network Plan Draft Methodology
neso.energy/document/363521/download

Technology infrastructure considered in the Principles

- Overhead lines (OHL)
- Underground cables (UGC) originating onshore, including those whose routes are partly offshore
- Cables originating offshore, including Offshore Transmission Owners and international interconnectors

Scope interactions

In Summer 2025, NESO published the draft methodology for the CSNP which will holistically plan wider reinforcements on the onshore transmission network alongside the offshore network. The CSNP follows a three-year cycle, with the first cycle anticipated to be published in 2027. The process, as drafted, is described in five stages; *Drive*, *Identify*, *Develop*, *Appraise*, and *Deliver*. ETDP will be a key resource used within the CSNP to develop reinforcement options to meet future network requirements.

The first stages; *Drive* and *Identify*, led by NESO, in collaboration with TOs, defines and evaluates the needs of the energy networks, considering future energy demand, supply and flexibility. They identify the technical needs of the onshore and offshore electricity networks, such as the requirement for additional capacity, security of supply, stability and voltage management services.

The Strategic Principles of ETDP promote these steps and support a firm basis upon which new electricity infrastructure planning proposals shall be formed.

The *Develop* and *Appraise* stages start to consider in more detail the potential reinforcement options including network management options, upgrades to the existing network, new circuits and whether these be onshore or offshore. The *Develop* and *Appraise* stages will primarily interact with the Strategic and Network Planning Principles as this is where the majority of options will be designed and appraised. The details of the options developed in the CSNP will consider Reinforcement Options including network upgrades and new circuits.

The options development in the *Develop* stage is predominantly undertaken by the three TOs and NESO, although third parties may also submit options to the process. This is where clear yet comprehensive guidance by the Principle's cascading structure described in Section 3 will benefit. The *Appraise* stage in CSNP process will ultimately decide what technology will be implemented including whether they are installed offshore or onshore. Whilst the CSNP sets out an appraisal methodology for each criterion, the Strategic and Network Planning Principles form overarching guidance for each option and aid in NESO's assessment.

Finally, the *Deliver* stage confirms options to progress to the delivery pipeline. This step includes the identification and handover to a delivery body who will be responsible for the detailed design and delivery of the infrastructure where the Project Development Principles will apply.

Mission Statement

To address the challenges identified in the TAAP and deliver on Recommendation RD1, the Principles:

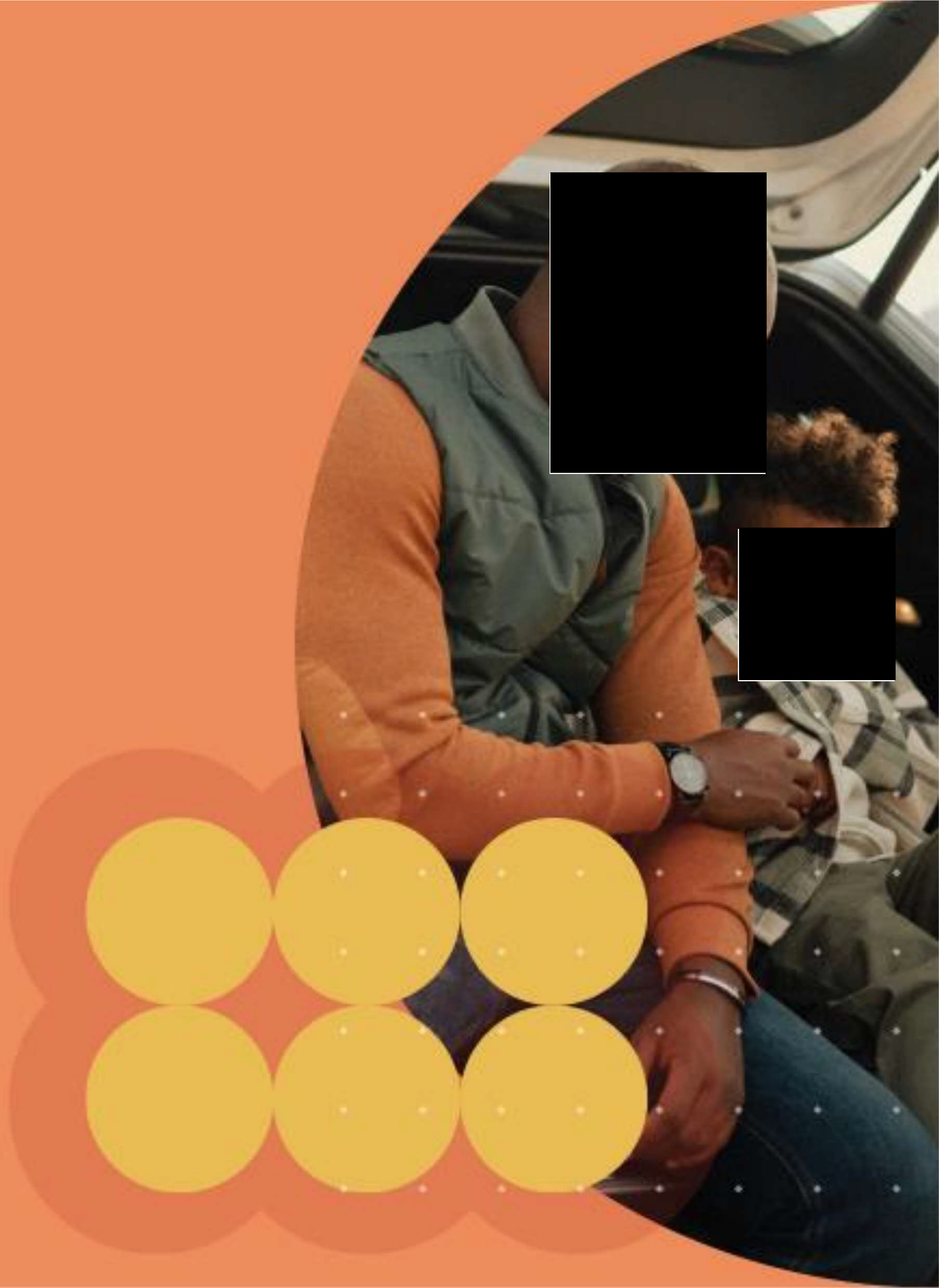
- Articulate unambiguous guidelines on transmission technology choices.
- Are sensitive to, and strive to mitigate the impact of transmission infrastructure on the environment, landscape, and communities.
- Set out clearly any route design flexibilities to be expected in any application of the principles.
- Encourage innovation, especially where that reduces transmission impacts effectively.
- Are compatible with Great Britain's regulatory principles, such that these principles promote economy and efficiency, as well as the Transmission Owners' licence obligations (from the Electricity Act 1989) to develop and maintain an efficient, coordinated, and economical system of electricity transmission.
- May be accepted and applied equally in England, Scotland and Wales, whilst recognising that landscapes differ across, and between, each of these nations and that by so doing, robustly support the swift planning decisions.

3. Overview of the Principles

ETDP Cascading Structure

Strategic Principles

Network Planning and Project Development



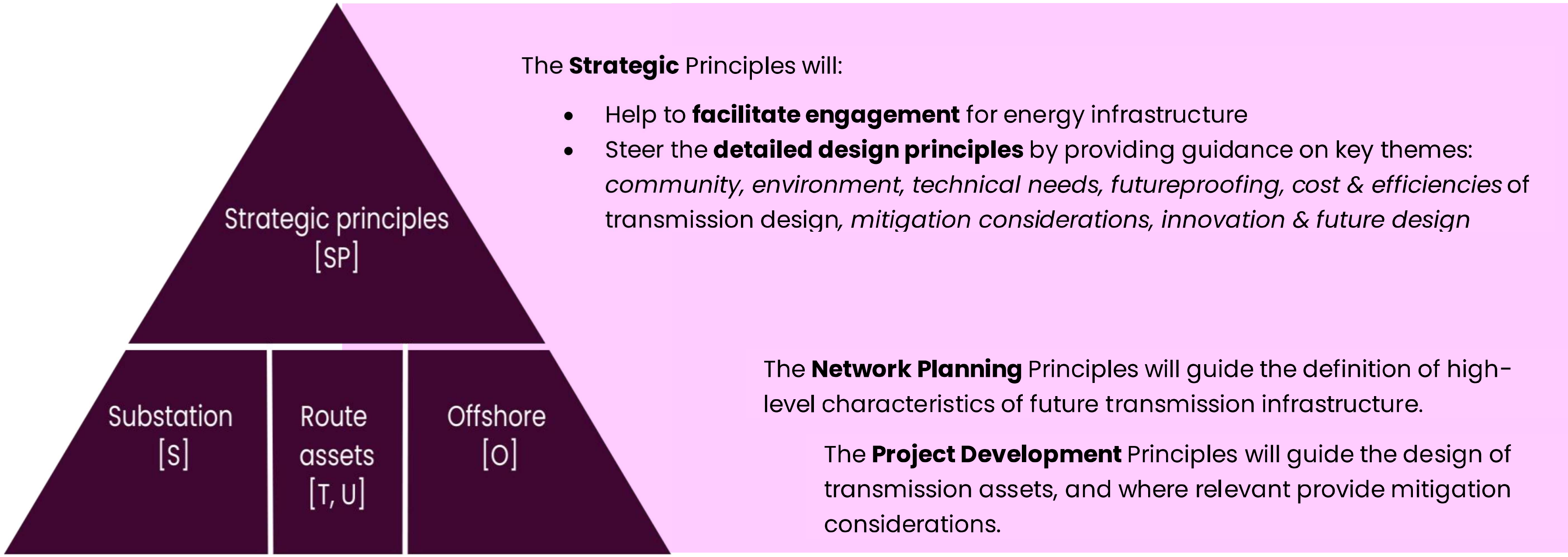
Overview of the Principles

The section is intended as a short introduction in how to read the Principles and to explain how and why the structure of the Principles was developed.

ETDP Cascading Structure

The ETDP document adopts a cascading structure, with Strategic Principles providing context and direction for the more specific Principles. The Principles apply to the Network Planning and Project Development stages of any transmission infrastructure project. The cascade structure is depicted below.

Figure 1: Cascading Structure of the Principles



Strategic Principles

There are three Strategic Principles which comprise of headline text, a brief introduction, and a set of bullets stating the premise. The Strategic Principles aim to:

- Provide coherent strategic direction for transmission developers and project designers.
- Promote discussion on the critical factors that influence design decisions.
- Steer the overall direction of downstream principles providing guidance on key themes: community, environment, technical needs, futureproofing, cost & efficiencies of transmission design, mitigation considerations, innovation & future design flexibility.

Network Planning and Project Development Principles

The Network Planning and Project Development Principles work within the provisions of the overarching Strategic Principles providing technology and asset specific guidance and design considerations to be applied at the relevant stage of a project's lifecycle.

Network Planning Principles focus on matters relevant to the early stages of project design, focussing on the high-level requirements and characteristics of the project such as those identified in Strategic Energy Planning processes such as the Centralised Strategic Network Plan.

Project Development Principles focus more so on detailed project considerations and design choices as well as potential impact mitigation opportunities.

Each Network Planning and Project Development Principle comprises:

- A headline text, providing design guidance, with the intention that deviations from this guidance may still be developed so long as they are justified within the design.
- A rationale for the headline, explaining the principle's necessity and benefits using clear, accessible language and a non-exhaustive set of leading design considerations.

Design Considerations may emphasise the complexity or breadth of factors that designers must consider, may mention possible impact mitigations, or may raise circumstances that could justify deviation.

4. Strategic Principles

SP1: Technical Needs

SP2: Environment, Community and Sustainability

SP3: Economics and Regulation

Strategic Principles

The Strategic Principles provide a clear and practical framework for good design, aligned with planning and regulatory requirements.

They will provide strategic direction to key stakeholders and translate high-level ambitions into strong design guidance that is accessible to both professionals and the wider public.

SP1 | Technical Needs

Good transmission design seeks to ensure that proposals for new infrastructure meet the current technical requirements and anticipate future technical need and developments, as identified by Great Britain's transmission development processes:

- Meet reliability and security targets.
- Deliver required connections or additional capacity cognisant of future needs to minimise the demand for recurring updates within recognised planning horizons.
- Protect the network's operability by ensuring its maintainability, flexibility, and resilience, to minimise the impact of current and future physical, cyber and climate related security risks.
- Use innovative technology and approaches, where appropriate, to safely unlock further technical value.

SP2 Environment, Community and Sustainability

Good transmission design understands, assesses, and improves environmental and social outcomes wherever feasible, embedding sustainability considerations at every stage:

- Protect or seek to avoid landscapes, environments and amenities of cultural and community importance, and actively reflect the views of communities and stakeholders wherever practicable.
- Use innovative technology and approaches, where appropriate, to further avoid or minimise environmental and social impacts and to offset residual effects.

SP3 Economics and regulation

Good transmission design delivers value for existing and future consumers by supporting regulatory targets:

- Promote economic, efficient and co-ordinated infrastructure designs and technologies, and support effective project delivery, improving lifetime efficiencies wherever feasible.
- Use innovative technology and approaches, where appropriate, to further efficiency and co-ordination, and to hasten the achievement of the Government's decarbonisation targets.

5. Network Planning Principles

Route Assets

Substations

Offshore

Network Planning Principles

The Network Planning Principles serve as design guidance to be applied at the relevant stage of a project's lifecycle.

This section contains:

- Route Assets: Principles T1 & T2
- Substations: Principles S1 to S3
- Offshore: Principle O1

T1	Consider the technical feasibility, economic, environmental, community, deliverability, and operability characteristics of all options to deliver the required transmission capacity and address future development need, including both onshore and offshore solutions where appropriate.
Rationale Section 9(1) of the UK Electricity Act 1989 places upon any electricity transmission licence holder the duty to "develop and maintain an efficient, co-ordinated and economical system of electricity transmission". This obligation is reflected in Condition B.7 of the Electricity Transmission Standard Licence Conditions (19 10 2021), with which all UK transmission owners must comply. At the same time, Schedule 9 of the same Electricity Act places a duty on the licence holder to preserve amenity: to "have regard to the desirability of preserving natural beauty, of conserving flora, fauna and geological or physiographical features of special interest and of protecting sites, buildings and objects of architectural, historic or archaeological interest; and" … "shall do what he reasonably can to mitigate any effect which the proposals would have on the natural beauty of the countryside or on any such flora, fauna, features, sites, buildings or objects." Alongside these factors, transmission asset designers must ensure that people and communities are also considered. Meeting this diverse set of requirements is a significant challenge for any transmission asset designer. The design of new transmission assets, such as overhead lines and underground cables, along with the selection of their preferred development options, involves many, sometimes conflicting, factors. In order to identify the most appropriate solution, designers should consider a broad range of feasible options, onshore and offshore, against the full range of requirements. These feasible options should explicitly include consideration of future development needs. Designing for the future may involve moderately higher upfront costs but can deliver long-term savings by avoiding the need for repeated interventions. It also enables faster deployment of	**Design considerations** • Transmission capacity need (the need for additional power transfer capability that justifies the new development in the first place). • Technical (such as the reliability and robustness of the proposed solution, ensuring compatibility with existing and future infrastructure and technology). • Operability (such as ease of operation and maintenance, flexibility and scalability for future upgrades, and resilience to adverse conditions e.g. wind, snow, pollution). • Deliverability (such as the feasibility of the site for construction, availability of materials and equipment, technology readiness level of the solution and system access impacts of any outages required). • Environmental (such as national landscape, ecological and heritage designations, hydrology and natural carbon stores). • Community (such as visual impact, cultural heritage, amenity, current land uses and settlement dispersion). • Economical (such as capital costs, operational costs and performance). • Holistic system needs (such as ensuring all factors are carefully balanced across all options to achieve the optimal overall solution, coordinate with other parts of the transmission network, and with other energy vectors). • Future development needs (such as those defined through network planning processes). • Opportunities to install higher voltage equipment and operating at a lower standard voltage in the interim.

T1	Consider the technical feasibility, economic, environmental, community, deliverability, and operability characteristics of all options to deliver the required transmission capacity and address future development need, including both onshore and offshore solutions where appropriate.
future infrastructure and reduces disruption to communities and the environment over time. The level of detail that goes into considering each option should be proportionate to its potential to meet the project's objectives and support a comprehensive and balanced evaluation to ensure the preferred option(s) is (are) robust and justifiable.	

References

- National Policy Statement for Electricity Networks EN-5, the Department for Energy Security and Net Zero (DESNZ), March 2023, Paragraph 1.1.7, Sections 2.7, 2.8
- UK Electricity Act 1989, Gov.uk, Section 9(1) and Schedule 9
- Electricity Transmission Standard Licence Conditions, Ofgem, June 2025, Condition B.7

T2	The design of onshore transmission circuits starts from the presumption that they will be continuous AC overhead lines.
Rationale Overhead line circuits are the preferred electricity transmission technology. This is because, despite their landscape and visual effects, compared to equivalent underground transmission cables they are usually: (i) quicker to construct, (ii) easier to access for maintenance and repair, (iii) have fewer environmental impacts along similar routes, (iv) more cost effective with a 4 to 5 times lower lifetime power transfer cost, (v) more future-proof, and (vi) easier to connect into existing or future circuits. In this context, a "continuous" overhead line refers foremost to a design with no underground sections. Great Britain's onshore supergrid employs double-circuit alternating current (AC[5]) overhead lines almost exclusively. This approach is typically the most cost-effective solution as it maximises the infrastructure's power transfer capacity and minimises materials consumption. At the same time, it enhances security of supply and minimises disruption to communities and the environment during construction and operation.	**Design considerations** • Differences in the national planning policies of the country in which the transmission circuits are proposed, noting that planning is a devolved matter and therefore subject to the frameworks of England, Wales, or Scotland. • In England and Wales, the starting presumption of overhead lines is reversed when proposed developments cross part of a nationally designated landscape (i.e. National Parks, The Broads, Areas of Outstanding Natural Beauty).
References • National Policy Statement for Electricity Networks EN-5, DESNZ, March 2023, Paragraph 2.9.20 • National Planning Framework 4 NPF4, Scottish Government, February 2023, Policy 11 • Approach to Routeing and Environmental Impact Assessment, SPEN, February 2020, Foreword from CEO • Comparison of Electricity Transmission Technologies: Costs and Characteristics, IET, April 2025 • HVDC Links in System Operations, ENTSO-E, Dec 2019. • Approach to Consenting, NGET, April 2022 • Planning Policy Wales Edition 12, Welsh Government, February 2024	

[5] High voltage direct current (HVDC) is an alternative transmission technology that, while more efficient over very long distances, particularly subsea, is less compatible with the interconnected, flexible, and distributed nature of the onshore Great Britain transmission system.

S1	Proposals for new substations, substation extensions and converter stations should meet the technical needs in a cost-effective way whilst considering environmental and community effects alongside deliverability and operability.

Rationale	Design considerations
Section 9(1) of the UK Electricity Act 1989 places upon any electricity transmission licence holder the duty to "develop and maintain an efficient, co-ordinated and economical system of electricity transmission". This obligation is reflected in Condition B.7 of the Electricity Transmission Standard Licence Conditions (19 10 2021), with which all UK transmission owners must comply. At the same time, however, Schedule 9 of the same Electricity Act places a duty on the licence holder to preserve amenity - to "have regard to the desirability of preserving natural beauty, of conserving flora, fauna and geological or physiographical features of special interest and of protecting sites, buildings and objects of architectural, historic or archaeological interest; and" … "shall do what he reasonably can to mitigate any effect which the proposals would have on the natural beauty of the countryside or on any such flora, fauna, features, sites, buildings or objects." Whilst people and communities are not mentioned in Schedule 9, transmission asset designers must ensure that these are also considered. Meeting this diverse set of requirements is a significant challenge for any transmission asset designer, and the design of a new substation, substation extension or converter station, along with the selection of a preferred site and layout, involves many, often conflicting, factors. The substation design process should evaluate environmental, community, and amenity effects and ensure designs demonstrate a commitment to sustainable and socially responsible infrastructure development whilst, at the same time, meeting technical, economic, deliverability and operability requirements and complying with relevant policies and licence obligations.	• Efficient (such as technical losses, operational complexity and deliverability). • Co-ordinated (with other parts of the transmission network, with the requirements of any directly connected Critical National Infrastructure (CNI), and with other energy vectors). • Economical (such as capital costs, operational costs, performance – particularly availability). • Environmental (such as national landscape, ecological and heritage designations, hydrology and natural carbon stores). • Community (such as visual impact, cultural heritage, amenity, current land uses and settlement dispersion). • Holistic system needs (such as ensuring all factors are carefully balanced across all options to achieve the optimal overall solution, coordinate with other parts of the transmission network, and with other energy vectors). • A preference for brownfield sites over greenfield, and a preference to avoid nationally important areas, such as Grade 1 agricultural land and sites of nationally scarce minerals. • Equipment specifications that allow operation at a higher voltage than initially required, to service future transmission system needs.

References

- Overarching National Policy Statement for Energy EN-1, DESNZ, March 2023, Section 2.6

S1	**Proposals for new substations, substation extensions and converter stations should meet the technical needs in a cost-effective way whilst considering environmental and community effects alongside deliverability and operability.**

- UK Electricity Act, Gov.uk, 1989, Section 9(1) and Schedule 9
- Electricity Transmission Standard Licence Conditions, Ofgem, June 2025, Condition B.7
- The Horlock Rules for the Siting and Design of Substations, National Grid Company, 2006 Rule#1: In the development of system options including new substations, consideration must be given to environmental issues from the earliest stage to balance the technical benefits and capital cost requirements for new developments against the consequential environmental effects in order to keep adverse effects to a reasonably practicable minimum.

S2	Operational flexibility during network outage should be considered in the electrical design and layout of all new substations, substation extensions, and converter stations.
Rationale Many substation design elements affect operational flexibility and network resilience, but two elements in particular – the substation electrical topology and the bay spacing - are totally dependent upon the space available. Since space is not easily increased after a site has been chosen, these two need to be considered very early in a substation's design. **Substation Topology** Every Main Interconnected Transmission System (MITS) substation has an impact on the transmission system's operational flexibility and resilience. One way a substation design can boost these two characteristics is by offering an alternative connecting point (busbar) to each of its transmission circuits so that, when any busbar needs to be maintained, network continuity can be sustained through another busbar. This is normally achieved by adopting a double busbar substation configuration[6] along with appropriate bus-section and coupler circuit breakers. However, for this to occur, the substation layout must include enough space, from the start, to accommodate the required double busbar, section and coupler topology. **Bay spacing** One way for substation design to improve the network's operational flexibility, and thus resilience, is by ensuring that, when one of the substation's circuit connection points (bays) needs to be maintained or repaired, this action can be safely achieved with a minimum (or no) need	**Design considerations** • Double busbar configurations are recommended for MITS supergrid substations. • Size and layout of substation footprint, particularly for strategically important substations. • Maintainability of both AIS and GIS substation bays with live neighbouring bays. • The differing requirements of MITS and customer only sites. Where a customer's site (not a MITS site) and the network can tolerate lower connection security, a single busbar or other configuration may be adequate.

[6] In accordance with NESO's Security and Quality of Supply Standard (SQSS), Appendix A

S2	Operational flexibility during network outage should be considered in the electrical design and layout of all new substations, substation extensions, and converter stations.
to also remove neighbouring bays from service. Again, for this to occur, Air Insulated Switchgear (AIS) substation layouts must include enough space and access around each bay, from the start, for them to be worked on safely with neighbouring bays live. For Gas Insulated Switchgear (GIS) substations, this same provision translates to incorporating sufficient space around the switchgear and Gas Insulated Busbar (GIB) equipment, in particular to facilitate lifting operations without impacting other circuits. It also translates to incorporating enough gas zones within the switchgear to allow interventions with single bay outages.	

References

- National Electricity Transmission System (NETS) Security and Quality of Supply Standard (SQSS), NESO, April 2025

S3	Consider current and anticipated future network needs in the location and layout of new substations including the availability of land to provide space for future connections.
Rationale Although designs for MITS substations cater for transmission connections known and planned for at the time of the original design, later on these same substations frequently need to accommodate further development triggered by new customer connection requests or wider system imperatives. However, these developments require additional physical space, which is acquired with much less time, cost, and disruption to neighbours and to the environment where the necessary land and planning provisions are negotiated at the time that the substation location is first established. This future-proofing principle doesn't propose a specific planning horizon; rather, it encourages proactive review of the above triggers (potential customer connections and wider system imperatives) to anticipate and justify appropriate strategic investment in land to reduce both future connection delays and incremental local disruption. It advocates a holistic, do-it-once approach to substation design, with the starting presumption that the substation's ground footprint and planning consent will be sized for the connections anticipated by network planning processes, even if some equipment is installed later, as required.	**Design considerations** • Land availability for the potential future expansion of the substation. • Strategic investment to acquire options on land or buildings that would help future proof the substation's ability to satisfy demands on its accommodation. • Coordination between network needs, customer needs, and future anticipated (not yet specifically identified) needs. • The appropriate mix of fully equipped bays, skeleton bays (bays with minimal equipment) and future bay space provision (substation space that is initially undeveloped). • Specification of switchgear capacity for futureproofing. • Any restrictions on future connection types due to spare bay sizing. • Space for anticipated (not yet specifically identified) transmission circuit entries, for circuit disposition between bus-sections, and for anticipated reactive compensation requirements. • For DC multipurpose substations, whether they are designed multi-terminal ready[7].
References • SSEN's Shetland multi-terminal link at 320 kV, Hitachi Energy, August 2020 • Tennet's approach for Germany and Netherlands, Tennet, April 2023 • CIGRE paper on Modular Offshore HVDC transmission planning principles, Cigre, 2024 • National Electricity Transmission System (NETS) Security and Quality of Supply Standard (SQSS), NESO, April 2025, Appendix A	

[7] Multi-terminal ready', as exampled by SSEN in Shetland, or Tennet for Germany and the Netherlands. Multi-terminal readiness considers the need to reserve offshore platform space for further bays and yet-to-be-refined HVDC circuit breakers as well as accommodating spare cable hang-offs and j-tubes in the platform design. Considerations are described by the referenced CIGRE paper on Modular Offshore HVDC transmission planning principles.

01 Strategic parameters, such as landfalls, routes, and technology for offshore cable corridors, should balance technical considerations with marine spatial constraints, considering potential impacts on the environment, community, and amenity, as well as deliverability and economic efficiency.

Rationale

Offshore cable corridor design at a strategic planning stage is foremost influenced by, and therefore must respect, the technical requirements of offshore cable technologies with marine spatial constraints. Key technical considerations at this stage include the required transmission capacity, number of circuits, and voltage level. Other factors, such as landfall location feasibility, route length, technology choice (High Voltage Alternating Current (HVAC) or High Voltage Direct Current (HVDC)), installation method feasibility and futureproofing, remain as design parameters to be balanced.

Design choices around these considerations interact differently with the marine spatial constraints and therefore impacts must be carefully balanced. Offshore corridors must navigate a complex marine environment shared with other users and protected areas such as shipping lanes, fishing grounds, military zones, historic environment assets, and environmentally sensitive habitats. Selection of suitable technology will inform the total project costs, delivery time, and spatial footprint. Alongside these considerations, the design process must also account for potential impacts on communities, environment, and economic efficiency. Offshore coordination (spatial and electrical) should be considered as a potential way of achieving further efficiencies, and where no material risks across the above-mentioned factors (technical, environmental, community, deliverability, economic) arise, or where risks can be reasonably managed, it should be taken forward.

Design considerations

- Technical needs for the provision of new transmission capacity and supporting SQSS requirements
- Potential for shared primary and auxiliary infrastructure onshore and offshore.
- Environmentally sensitive or protected areas, both on- and offshore (e.g. benthic marine protected areas), and the feasibility and cost of finding a proportionate environmental compensation for potential impacts thereon.

Offshore cable corridor considerations:

- Potential for shared cable corridors.
- Potential for shared marine survey campaigns.
- Marine constraints including (but not limited to) the marine ecology, marine physical environment, marine historic environment, seabed geology and topology, other marine infrastructure and sea users.
- Offshore areas that have restricted navigation i.e., moorings and shallow waters.
- Known wrecks and areas of archaeological/historical importance.
- Hazardous seabed terrain (e.g., bedrock outcrop, boulder fields, excess slopes, mobile sediments etc.).
- Third parties, including high intensity demersal and static gear fishing areas, local tourist trade, military practice zones and aggregate extraction areas/dredged channels.
- Anchorage areas, traffic separation schemes & high-density shipping lanes.
- Marine protected areas and sensitive nature conservation areas.

<table>
<tr><td>01</td><td colspan="2">Strategic parameters, such as landfalls, routes, and technology for offshore cable corridors, should balance technical considerations with marine spatial constraints, considering potential impacts on the environment, community, and amenity, as well as deliverability and economic efficiency.</td></tr>
<tr><td colspan="2"></td><td>Landfall considerations:

• Physical characteristics of the coastline and area in the direct vicinity of landfalls.
• Availability of onshore space at the landfall location to host the required AC substations or DC converter stations and other auxiliary equipment.
• Availability of onshore transmission capacity in the vicinity of landfall locations.
• Presence of communities and/or sensitive environment in the vicinity of landfall locations who can be affected during construction and maintenance.
• Presence of other infrastructure.</td></tr>
<tr><td colspan="3">References
• HND Follow Up Exercise Methodology, NESO, November 2022
• Export transmission cables for offshore renewable installations, Principles of Cable Routeing and Spacing, Crown Estate, 2012</td></tr>
</table>

6. Project Development Principles

Overhead Lines

Underground Cables

Substations

Offshore

Project Development Principles

The Project Development Principles serve as design guidance to be applied at the relevant stage of a project's lifecycle.

This section contains:

- Overhead Lines: Principles T3 to T7
- Underground Cables: Principle U1
- Substations: Principles S4 to S10
- Offshore: Principles O2 & O3

T3	The starting presumption for support structures for double circuit overhead transmission lines is that they be of a steel lattice design.
Rationale Where double circuit overhead transmission lines are selected, steel lattice towers offer several benefits over other forms of support structures (e.g. monopole constructions such as T-pylons). They have lower levels of embodied carbon (less concrete and steel, whilst still retaining excellent structural integrity), they are easier to construct and maintain (in general they do not require permanent access roads and they can be serviced using smaller site vehicles), and they are more cost-effective. In addition, the lengths of steel angle-section used in lattice towers can be more easily transported to, and assembled in, hard-to-access areas than the prefabricated sections of monopole designs causing less disruption to the environment and local ecology. Alongside other benefits, the relatively open silhouette of lattice towers make them easier to see through, allowing them to be backdropped by local landscape features (especially in wooded or moorland areas). However, in certain highly situation-dependent settings, monopole constructions may offer an improved visual appearance. Overhead lines form the backbone of the electricity supply to the national economy, so must continue to operate reliably through the very harshest British weather conditions. For this reason, whatever factors contribute to the selection of a transmission support design for a given project, be they technical, visual or both, only thoroughly tested, high-quality designs should be considered.	**Design considerations** • Altitude, wind-speeds and ground conditions for the foundations. • Where adverse effects of steel lattice towers on key receptors cannot be mitigated by careful routeing, consider whether alternative tower designs could be visually advantageous and economically justified. • Differences in national planning policy frameworks degrees of protection between England, Wales, and Scotland. • Locations of any transitions between different tower designs along a continuous route, considering technical requirements and visual impact. • Wood poles as a proven alternative to single circuit steel lattice designs (132 kV in Scotland only), where future double circuit capacity is not envisaged. • Opportunities to install structures capable of supporting higher voltages operation and operating at a lower standard voltage in the interim.
References • UK Electricity Act 1989, Gov.uk, Section 9(1) and Schedule 9 • Approach to Consenting, NGET April 2022	

T3	The starting presumption for support structures for double circuit overhead transmission lines is that they be of a steel lattice design.

- Approach to Routeing and Environmental Impact Assessment, SPEN, February 2020, p19
- The Holford Rules, Lord Holford, 1959, p5 – "In additional [sic] to adopting appropriate routeing, evaluate where appropriate the use of alternative tower designs now available where these would be advantageous visually, and where the extra cost can be justified."
- National Planning Framework 4 NPF4, Scottish Government, February 2023, Policy 11
- National Policy Statement for Electricity Networks EN-5, Department for Energy Security and Net Zero (DESNZ), March 2023
- Comparison of Electricity Transmission Technologies: Costs and Characteristics, IET, April 2025

T4	Route options for overhead lines should seek to avoid or minimise the impact on areas of amenity value which are afforded protection through national planning policies, acknowledging the hierarchy of protection designations.

Rationale	Design considerations
The most direct route between two substations is usually the most economic choice for new overhead lines, as it has the potential to minimises the length of infrastructure required and therefore reduces materials and construction costs. However, in developing route options for new overhead lines, designers may encounter areas of particular sensitivity. These may include settlement areas, designated landscapes, protected habitats, and Heritage Coasts. National Policy Statements (NPS) for England and Wales, and National Planning Framework 4 (NPF4) for Scotland, assign varying levels of protection of amenity to these areas that should be considered and addressed by all proposals for new developments. Design should endeavour to avoid or minimise, the impacts on the amenity value of sensitive areas. It is important to balance the hierarchy of designated protection in national planning policies against the costs of routeing an overhead line to avoid areas of amenity value.	• The type and extent of protection afforded to designated areas or buildings under relevant national planning policies[8] • Differences in policy frameworks and protection levels between England, Wales, and Scotland. • Trade-offs associated with lengthening routes to avoid protected areas, including the additional number, location and impact of the larger angle towers which are required. to change the direction of the new overhead line.

References

- National Policy Statement for Electricity Networks EN-5, DESNZ, March 2023
- National Planning Framework 4 NPF4, Scottish Government, February 2023
- UK Electricity Act 1989, Gov.uk, Section 9(1) and Schedule 9
- The Holford Rules, Lord Holford, 1959
- Rule#1 'Avoid altogether, if possible, the major areas of high amenity value, by so planning the general route of the line in the first place, even if the total mileage is somewhat increased in consequence.'

[8] For example, the NPS EN-5 [2.9.12] states for England and Wales that "*in nationally designated landscapes (for instance, National Parks, The Broads and Areas of Outstanding Natural Beauty) even residual impacts may well make an overhead line proposal unacceptable in planning terms*".

T4	Route options for overhead lines should seek to avoid or minimise the impact on areas of amenity value which are afforded protection through national planning policies, acknowledging the hierarchy of protection designations.

- Rule#2 ‘Avoid smaller areas of high amenity value, or scientific interest by deviation; provided that this can be done without using too many angle towers, i.e. the more massive structures that are used when lines change direction.’
- Rule#3: ‘Other things being equal, choose the most direct line, with no sharp changes of direction and thus with few angle towers. ’

T5	Route options for overhead lines should seek to balance the impacts on communities, landscape and visual amenity with other environmental and technical considerations.

Rationale	Design considerations
Overhead line routes traverse areas of varying landform, topography, ecology, land use and population. The routeing and design of an overhead line must consider competing environmental, community and technical considerations, each of which require careful consideration to minimise the overall impact. This could involve, for example, balancing the benefits of avoiding prominent skylines or ridgelines and using natural screening (e.g. trees or hills) to break up views of the infrastructure and reduce perceived height of supports, against the potential drawback of routeing in lower-lying areas which may bring infrastructure closer to settlements and properties. Re-routeing part of the line is likely to affect adjacent sections of the line. Design should, therefore, demonstrate how often competing considerations, are balanced along the length of the overhead line route.	• Proximity to settlements and land use categories, including residential, industrial, and mixed-use areas. • Topography and landform features that influence visibility and provide opportunities for screening. • Cumulative visual impacts from existing electricity infrastructure and other developments. • Opportunities to maintain visual consistency in tower design, height, and alignment. • Ecology, including wildlife areas such as woodlands, wetlands or bird migratory routes. • Deliverability and accessibility of the route for construction and ongoing maintenance.

References

- The Holford Rules, Lord Holford, 1959
- Rule#4: 'Choose tree and hill backgrounds in preference to sky backgrounds wherever possible; and when the line has to cross a ridge, secure this opaque background as long as possible and cross obliquely when a dip in the ridge provides an opportunity. Where it does not, cross directly, preferably between belts of trees.'
- Rule#5: 'Prefer moderately open valleys with woods where the apparent height of towers will be reduced, and views of the line will be broken by trees.'
- Rule#7: 'Approach urban areas through industrial zones, where they exist; and when pleasant residential and recreational land intervenes between the approach line and the substation, go carefully into the comparative costs of the undergrounding, for lines other than those of the highest voltage.'

T6	Where a continuous overhead line route cannot be identified, consider forms of mitigation for environmental, community and technical impacts.
Rationale Where a proposed new continuous overhead line route[9] passes through one or more protected areas and re-routeing is not feasible, a review of the likely adverse effects should be undertaken as part of the Environmental Impact Assessment (EIA) to determine whether there is an emerging case for considering other forms of mitigation. Mitigation options come with their own set of challenges and must be thoroughly justified in balancing economic viability, technical feasibility and the extent of the predicted effects on a receptor or grouping of receptors. Alternative tower designs, such as monopole and low-height steel lattice towers, can reduce landscape disruption and lessen visual impacts in certain situations. However, these designs are often more difficult to construct and maintain. They may also have higher levels of embodied carbon compared to traditional full-height steel lattice towers. Additionally, their increased costs must be weighed against their effectiveness. Where the effects on a particular sensitive receptor or group of receptors, in cognisance of stakeholder feedback, are assessed by the relevant professional as being over and above the thresholds of significance defined in relevant EIA legislation and guidance, or where the technical feasibility brings into question the continuity of an overhead line, and where these effects cannot be otherwise mitigated, undergrounding sections of the line may be the only viable alternative. The assessment of potential underground solutions must carefully consider the advantages and disadvantages of undergrounding, taking cognisance of costs and	**Design considerations** • Alternative tower designs, including lower height steel lattice towers and monopoles. • Where factors are identified that call into question the continuity of an overhead line route, carefully consider the advantages and disadvantages of undergrounding, without incurring excessive costs and the technical issues associated with undergrounding. • As a guiding example, undergrounding a section of a line should be carefully considered where it crosses a National Park, Area of Outstanding Natural Beauty or a National Scenic Area, provided no suitable overhead line route can be identified. • Ground conditions preventing certain cable ratings, complex crossings with other infrastructure, other designations and limited access areas. • Availability of space for cable sealing end compounds and their impacts on the visual amenity. • Holistic impact of the proposed mitigation measures on the project – the balance between the benefits achieved through the mitigation and the costs and risks involved therein.

[9] In this context, a “continuous” overhead line refers to a design with no underground sections and consistent support structures used throughout the route.

T6	Where a continuous overhead line route cannot be identified, consider forms of mitigation for environmental, community and technical impacts.
effects of associated technical issues within the context of relevant license obligations.	

References

- National Policy Statement for Electricity Networks EN-5, DESNZ, March 2023, Paragraphs 2.9.20, 2.9.23 to 2.9.25
- National Planning Framework 4 NPF4, Scottish Government, February 2023, Policy 11(e)
- Comparison of Electricity Transmission Technologies: Costs and Characteristics, IET, April 2025
- Approach to Routeing and Environmental Impact Assessment, SPEN, February 2020, p9

T7	Consider overhead line transmission routes and designs that minimise susceptibility to high-impact physical and climate-related events.
Rationale Intense flooding, coastal erosion, and the increasing frequency of extreme weather events are all effects of climate change which threaten the resilience of Great Britain's transmission networks. Whilst overhead lines are designed to be exposed to sustained periods of wind and rain, temperature fluctuations and ice loading, this infrastructure remains susceptible to more severe external influences, for example very high temperatures and airborne debris. Environmental hazards such as flooding and wildfires can compromise the mechanical integrity of conductors and tower structures, posing a risk to the safety of the equipment and its surroundings. Disruptions can be temporary, for example, owing to an electrical flashover across the insulation, or more permanent, such as a compromised tower structure. The resulting failure of an overhead transmission line becomes not only a safety hazard, but can undermine the system's operational flexibility, heightening the risk to security of supply. In addition to environmental risks, transmission routes may also be exposed to malicious threats, such as sabotage or coordinated attacks. Once constructed and in operation, transmission infrastructure is rarely relocated due to its scale and its integral role to the operation of the transmission system at any given time. Moreover, overhead lines constructed using steel lattice towers are generally designed to operate for up to 80 years, so it is vitally important to account for physical and climate related risks in their routeing and design.	**Design considerations** • Risk zones, including areas prone to natural hazards such as flooding, land slip, high winds, icing, and wildfires, can restrict access for maintenance or repair. Risks can be mitigated with strategies such as designing for flood resilient infrastructure, crossing at a risk zone's narrowest point, as directly as possible, spanning the lowest flood levels by choosing tower locations above normal flood levels.

References

- ETR 138 Resilience to flooding of Grid and Primary substations, ENA, 2018

T7	Consider overhead line transmission routes and designs that minimise susceptibility to high-impact physical and climate-related events.

- CCAR4 ENA Fourth Round Climate Change Adaptation Report, ENA, December 2024
- Approach to Routeing and Environmental Impact Assessment, SPEN, February 2020, p12
- National Policy Statement for Electricity Networks EN-5, DESNZ, March 2023, Section2.3 "…ensure that electricity networks infrastructure is resilient to the effects of climate change."
- Electricity Safety, Quality and Continuity Regulations, Gov.uk, 2002

U1 Where underground transmission cables are proposed, respect the constraints of underground technology, including ground conditions, land use and access considerations in the design of the route, balancing impacts on the community, landscape and visual amenity and environmental considerations.

Rationale

Underground transmission cable routeing differs fundamentally from the landscape-led approach used for overhead lines. While overhead line design prioritises minimising visual and landscape impacts, underground cable routeing is primarily engineering-led. This means routes are determined by technical feasibility, constructability, safety, and cost. High-capacity underground circuits require wide construction swathes (typically 35–70 metres) to allow for heat dissipation, with trenches buried around 1.2 metres deep. These physical requirements, combined with the need to avoid challenging ground conditions, flood zones, and sensitive habitats, and the greater motivation for routes to be shorter due to the increased cost of underground cables, often result in routes that diverge significantly from those of an equivalent overhead line.

Although, with the exception of the cable sealing ends, they are less visually intrusive post-construction, underground cables cause substantial ground disturbance and have the potential to increase landowner impacts during installation, compared to an equivalent overhead line. The success of reinstatement varies by land type, being quicker in agricultural land and most visible in uplands or semi-natural areas. Unlike overhead lines, which can span certain obstacles such as rivers and railways, underground cables typically avoid them or use specialist and expensive methods, such as horizontal directional drilling (HDD) or tunnelling, to install the cables safely under the obstacle. This can significantly increase project costs and in some locations may not be technically feasible. As such, careful route selection, habitat reinstatement, and long-term access planning are essential to minimise both temporary and permanent environmental effects.

Design considerations

- Technical constraints including bending radius, heat dissipation of cables, access for maintenance and additional equipment to provide reactive power compensation, where relevant, for underground cables.
- Disturbances during construction and repair (noise, visual, air quality, environmental, soil, drainage, archaeology).
- Opportunities to route along existing disturbed corridors such as roads or existing infrastructure to reduce new impacts, being mindful of physical resilience implications and access requirements during construction and operation.
- Ground conditions including risk of contamination and ground stability.
- Longer construction and repair times than overhead lines.
- The requirement to build additional above ground infrastructure such as cable sealing end compounds and link pillars together with the need for reactive compensation equipment at nearby substations (physical limitations of distancing for reactive compensation stations).
- Safety and land use requirements in areas directly above the buried cables.
- The cost and availability of underground cables for a given application, which may vary on a case-by-case basis.
- Susceptibility to high-impact physical and climate related events, including flooding.

U1	**Where underground transmission cables are proposed, respect the constraints of underground technology, including ground conditions, land use and access considerations in the design of the route, balancing impacts on the community, landscape and visual amenity and environmental considerations.**

References

- Approach to Routeing and Environmental Impact Assessment, SPEN, February 2020
- Undergrounding high voltage electricity transmission lines - The Technical Issues, NGET, January 2015

<table>
<tr><th>S4</th><th>Where possible, locate new substations or converter stations near to the infrastructure to which it will connect.</th></tr>
<tr><td>Rationale

During the Project Development stage, when locational flexibility is more limited than at the Network Planning stage, siting decisions should be optimised to reduce infrastructure requirements and their associated impacts. For new substations or converter stations that connect to existing infrastructure, locating them in close proximity to these existing assets typically reduces the extent of new connection infrastructure required, including any necessary diversions of existing circuits, reducing both cost and associated impacts.</td><td>Design considerations

• Distance to existing transmission infrastructure requiring connection or diversion.
• Number and configuration of circuit entries and exits and the length and routeing complexity of new transmission connections required
• Land availability and ground conditions.
• Access requirements for construction and maintenance.</td></tr>
<tr><td colspan="2">References
• Informed by discussions and engagement with transmission project developers.</td></tr>
</table>

S5	Choose locations for new substations and converter stations that minimise susceptibility to high-impact physical and climate related events, where possible.
Rationale Extreme climate related events, such as floods, land slip, wildfires and heatwaves, present an enduring threat to the resilience of Great Britain's transmission networks. These events are increasing in frequency and intensity due to climate change, which poses new challenges for designers of transmission substations. Substations are also susceptible to malicious threats, such as sabotage or coordinated attacks. With effective siting and design these risks can often be minimised to ensure infrastructure security and operational continuity. Once constructed and in operation, transmission infrastructure is rarely relocated due to its scale and its integral role to the operation of the transmission system at any given time. Moreover, substations are generally designed to operate for 40 years, or longer, so it is vitally important to account for physical and climate related risks in the positioning and design of new transmission infrastructure.	**Design considerations** • Areas prone to natural hazards such as flooding, land slip, high winds, icing, and wildfires. • Electrical redundancy and diversity of substation auxiliary supply. • Single points of failure for incoming and outgoing circuits of Main Interconnected Transmission System (MITS) substations. • Materials and equipment that operate efficiently under foreseeable environmental conditions. • Mitigation measures, for example, flood prevention measures including water barriers, raising equipment within a substation or converter station, and land management-based measures. • Ease of operational and maintenance access. • Measures to deter non-authorised entry onto substations.
References • Flood defence framework for National Grid substations in United Kingdom, Climate Adapt, 2019 • Enhancing Resilience in UK Energy Networks, DESNZ, April 2024 • Electricity Safety, Quality and Continuity Regulations, Gov.uk, 2002	

S6 Substation or converter station design choices related to indoor or outdoor, and to air insulated or gas insulated switchgear, should be based on site-specific factors including environmental and community impacts, spatial constraints and whole-life cost.

Rationale (general)

Buildings: A substation may be installed either outdoors or indoors in a protective building.

Technology: A substation's switchgear is based upon one of two technologies: either the connections and busbars are insulated from ground and from each other by air - Air Insulated Switchgear (AIS), or they are placed in tubular metal enclosures and insulated from ground by an insulating gas - Gas Insulated Switchgear (GIS).

Both installation types and both technologies have their advantages, as outlined next.

Rationale (indoor or outdoor?)

Transmission substations may be installed outdoors or enclosed in protective buildings. Whilst it is less costly to install substations outdoors, there are a few reasons why some substations are installed indoors, key amongst them being:

- For GIS: The UK climate tends to degrade the external parts of GIS, impacting its long-term reliability and, in particular, compromising its ability to effectively retain the insulating gas, so GIS equipment is normally, though not always, enclosed indoors. An exception to this is Gas Insulated Busbar (GIB), which is frequently installed outdoors to facilitate connections to incoming transmission circuits.
- For AIS: Pollution, such as salt from blown sea spray, or industrial pollution, would degrade the performance of AIS substation steelwork, insulators and other components. Therefore, AIS substations exposed to these risks may well be installed indoors to mitigate these risks. The physical scale and associated costs of the required building become increasingly significant at higher transmission voltages.
- For AIS: Extreme weather risk (for example, heavy icing, severe snow, high winds) in some locations may lead to the judgement that, for substations in these areas, network operability and resilience are enhanced by enclosing them, or part of them, indoors.

Rationale (AIS or GIS technology?)

- Technically, AIS substations are simpler to repair than GIS. On the other hand, healthy GIS equipment is simpler to maintain and can be maintained less frequently than AIS. Another technical factor is the substation building; AIS can be installed indoors or outdoors depending upon the severity of the weather and pollution levels, however, at least in the UK, GIS is normally installed indoors to preserve its operational reliability , and an indoor GIS solution is generally more cost effective than an indoor AIS solution due to the prohibitive cost of an AIS substation building. The expected lifetime of indoor GIS equipment is greater than outdoor equipment as the equipment is protected from the environment.

S6 **Substation or converter station design choices related to indoor or outdoor, and to air insulated or gas insulated switchgear, should be based on site-specific factors including environmental and community impacts, spatial constraints and whole-life cost.**

- Should a substation extension be required in the future, and assuming the extra space is available, AIS is easier to extend and has lower reliance on the original equipment manufacturer than GIS, though a full replacement of an AIS substation can be more challenging than a GIS replacement.
- For AIS substations, individual asset replacement or refurbishment can be used to target specific assets; however, should a full site replacement be required, this can be challenging due to the space required for an offline replacement or the operational complexities associated with an in-situ replacement.
- Environmentally, the size of the substation footprint will proportionally affect the volume of earthworks and quantities of concrete and steel required during construction, with some biodiversity impacts also scaling proportionally. Conversely, GIS involves greater use of metal in its insulating enclosures compared to AIS. A site-specific assessment should consider the balance of these factors. Meanwhile operationally, AIS substations almost invariably use much smaller amounts of insulating and interrupting gas and have less gas seals to manage per bay than equivalent GIS substations. Historically, the IIG used in both AIS and GIS has been sulphur hexafluoride (SF6), which has a very powerful global warming potential (GWP). From around 2025, GIS installations will use SF6-free F-gases, and AIS installations are expected to follow this practice within the next 1-2 years. SF6-free F-gases still have high GWP, but a leakage of SF6-free F-gas will have an environmental impact only 1-2% of that of the same mass of SF6 so this is anticipated to become less of an environmental issue in future.
- Community- wise, the comparative effects of the two technologies depend upon the local landscape, the extent of the land take and upon the degree of visual impact mitigation applied to the site. Regarding the space requirement, the headline benefit of GIS is that it needs a smaller ground footprint than AIS. However, this only relates to the switchgear itself, not to the other substation components, such as transformers, reactive compensation, and overhead line entries. For this reason, the space-saving benefit of GIS is usually less pronounced for substations with a greater number of circuits, where the other substation components increasingly affect the land area requirement. Regarding visual impact, where AIS is installed outdoors, the relatively open silhouette of AIS and its smaller ancillary buildings, compares with the larger GIS building that is taller, wider and longer than the equipment it contains. Except in built-up areas, screening by trees and earthworks can equally be applied to both substation technologies to reduce the visual impacts.
- Cost-wise, the purchase cost for GIS equipment is normally higher than for the AIS equivalent , although the overall lifetime cost comparison for the full solution between the two technologies will depend upon many factors including the location, land-take and planning conditions, the cost of land, the need for a substation building, the extent of earthworks, carbon costing, and projected maintenance and repair costs.

Given the above factors, outdoor AIS can often be the economic choice for new substation designs. However, the key benefit of GIS, namely that it requires a significantly reduced ground footprint compared to that of AIS, means it can offer economic and efficient solutions in space-constrained circumstances for which AIS cannot be considered or in less constrained areas can provide greater opportunities for future expansion. GIS is thus a valuable option in the transmission designer's toolbox.

S6	Substation or converter station design choices related to indoor or outdoor, and to air insulated or gas insulated switchgear, should be based on site-specific factors including environmental and community impacts, spatial constraints and whole-life cost.

Design considerations

Substation design is complex and affected by many variables:

- Where space is unconstrained and there is a low risk from pollution or extreme weather, outdoor AIS can often be the most economic and efficient solution, whereas indoor GIS is generally more suitable where space is constrained or there is risk from pollution or extreme weather.
- Visual impact from key viewpoints considering the smaller footprint of a GIS building versus the larger footprint and openness of AIS.
- Expected pollution levels (salt spray or other airborne pollution).
- Severity of anticipated weather conditions such as heavy icing or high winds.
- The availability of consentable land areas.
- The GWP of the composition of gases that comprise the insulating medium. (Whilst distinctly less potent than legacy SF6, an insulating medium that contains a mixture of the F-gas Fluoronitrile (C4-FN) is still a powerful greenhouse gas.)
- Ecological and resources effects such as disturbance of peat and mineral-rich soils

References

- The Horlock Rules for the Siting and Design of Substations, National Grid Company, 2006, Rule#7 Note 8 'Where there are particular technical or environmental constraints, it may be appropriate to consider the use of GIS equipment which occupies less space and is usually enclosed within a building'
- Evaluation of Different Switchgear Technologies (AIS, MTS, GIS) For Rated Voltages of 52 kV an Above (390), Cigre, August 2009

S7	Optimise, with respect to its surroundings, the space to be occupied by any new substation or converter station, its line entries, and potential future extensions.
Rationale Whilst Substation Design Principle S3 urges the designer to set aside enough space for current and future substation needs, this complementary Principle focuses upon using that space efficiently, balancing technical requirements with careful regard to the community and the uses of land into which it is placed, to minimise disruption to the lives, businesses and environment that its arrival effects. Early consultation with stakeholders allows understanding of the local issues, as a first step to optimising the location and layout of the substation and its transmission line entries. Consideration should be given to mitigating any changes of access to roads, buildings, footpaths and fields and to the useability of land parcels that are left surrounding the station. Consideration should also be given to mitigating visual and acoustic noise effects. In rural locations this could be through tree planting or earthworks, for which additional ground space would most likely be required whilst, in urban environments, suitable perimeter walls or buildings might offer the most appropriate impact mitigation of visual effects.	**Design considerations** • Access and egress for abnormal indivisible loads. • Access and accommodation for Construction. • Access, egress, and control point facilities for emergency services (fire, police and ambulance). • Utility diversions. • Detour lengths and routes for established rights of way. • Drainage considerations, minimising environmental impacts and maintaining established field boundaries.
References • The Horlock Rules for the Siting and Design of Substations, National Grid Company, 2006 • Rule#4: 'The siting of substations, extensions and associated proposals should take advantage of the screening provided by landform and existing features and the potential use of site layout and levels to keep intrusion into surrounding areas to a reasonably practicable minimum. ' • Rule#6 'The land use effects of the proposal should be considered when planning the siting of substations or extensions.' • Rule#8: 'Space should be used effectively to limit the area required for development consistent with appropriate mitigation measures and to minimise the adverse effects on existing land use and rights of way, whilst also having regard to future extension of the substation.'	

S8	Consider the implications of overhead line and underground cable connections in the siting and design of substations or converter stations, and any mitigation or enhancement required.
Rationale Where overhead lines converge and enter a substation or converter station, the visual effect of the lines and their terminal towers, or 'wirescape' must be carefully considered. The design of these assets should endeavour to mitigate cumulative wirescape issues by siting line entries and using visual screening in this way helping to ensure that landscape and environmental factors are considered alongside technical requirements.	**Design considerations** • Existing and planned overhead line entries, potential conglomerations of structures and wires, as seen from key viewpoints. • Cumulative visual impacts at key viewpoints due to anticipated substation or converter station extensions or new line entries. • Visual impact mitigation such using landscaping as screening. • Environmental impacts. • Planned customer connections to sites via either overhead line or underground cables.
References • The Horlock Rules for the Siting and Design of Substations, National Grid Company, 2006 • Rule#6: 'In country which is flat and sparsely planted, keep the high voltage lines as far as possible independent of smaller lines, converging routes, distribution poles and other masts, wires and cables, to avoid a concatenation or 'wirescape.' • Rule#7: 'In the design of new substations or line entries, early consideration should be given to the options available for terminal towers, equipment, buildings and ancillary development appropriate to individual locations, seeking to keep effects to a reasonably practicable minimum.' • Rule #10: 'In open landscape especially, high voltage line entries should be kept, as far as possible, visually separate from low voltage lines and other overhead lines so as to avoid a confusing appearance.'	

S9	Where possible, the design of substations, converter stations, access roads and other ancillary developments should consider the local environment in the vicinity of the new infrastructure.

Rationale

A new substation or converter station, with its access road and other ancillary developments can have a considerable impact upon the ecology, hydrology and visual amenity of the locality. However, with careful consideration during the project development stage, most effects can at least be mitigated, if not avoided.

Substation and converter station design should ensure that, whilst any new substation achieves its functional purpose, its impacts on its surroundings are studied during design so that impacts can be mitigated to the extent practicable. For visual impact mitigation this could take the form of careful siting and layout of the infrastructure, consideration of the design, colour and form of buildings, or partial visual screening with vegetation or earthworks. For ecological impacts, substation design should endeavour to minimise negative effects.

Design considerations

- Ecological effects on the surrounding area, including potential impacts on habitats and species.
- Hydrological conditions, such as flood risk and water flow patterns, which influence both siting and design of infrastructure and access roads.
- Visual impact from key viewpoints, with opportunities for mitigation through siting, layout, building form, colour, and screening measures.

References

- The Horlock Rules for the Siting and Design of Substations, National Grid Company, 2006
- Rule#1: 'In the development of system options including new substations, consideration must be given to environmental issues from the earliest stage to balance the technical benefits and capital cost requirements for new developments against the consequential environmental effects in order to keep adverse effects to a reasonably practicable minimum.'
- Rule#3: 'Areas of local amenity value, important existing habitats and landscape features including ancient woodland, historic hedgerows, surface and ground water sources and nature conservation areas should be protected as far as reasonably practicable.'
- Rule#5: 'The proposals should keep the visual, noise and other environmental effects to a reasonably practicable minimum'
- Rule#9: 'The design of access roads, perimeter fencing, earth shaping, planting and ancillary development should form an integral part of the site layout and design to fit in with the surroundings.'
- Rule#11: 'The inter-relationship between towers and substation structures and background and foreground features should be studied to reduce the prominence of structures from main viewpoints. Where practicable the exposure of terminal towers on prominent ridges should be minimised by siting towers against a background of trees rather than open skylines.'

S10	When designing substations, substation extensions, and converter stations, seek to minimise carbon impact in construction and operations
Rationale As with all major infrastructure projects, the construction of substations and extensions depends on materials such as concrete and steel, which are often manufactured using relatively carbon-intensive processes. Designers should seek to minimise the lifetime carbon impact from these sources whilst also considering other sustainable construction and operational solutions that may arise from time to time.	**Design considerations** • Extent of disturbance to natural carbon sequestration (e.g. trees, peat, wetlands, ponds and, offshore, seaweed). • The degree to which the substation's layout follows land contours, to minimise energy-consuming earth-moving. • Type(s) of concrete used, and associated water consumption. • Potential for natural air and oil flow cooling systems to reduce operational emission, supported by appropriate equipment and thermal design, and noting the trade-off with this leading to larger equipment sizing. • Balance between lifetime operational emissions from technical losses and cooling, and the embodied carbon from equipment manufacture.
References • Informed by discussions and engagement with transmission project developers.	

O2	In the design of offshore cable routes, and their respective points of landfall, consider opportunities and risks arising from coordination with other existing and planned offshore infrastructure in the region

Rationale

Developers of offshore electrical infrastructure should look for ways to coordinate with other projects. This could include, at the earlier stages of a project's development, consideration of shared cable corridors, common infrastructure, and coordinating development timelines. Aligning cable paths and landfall sites can help reduce environmental impacts, especially in protected coastal and marine areas. Coordination can bring several benefits:

- More efficient use of space by routeing multiple cables along parallel corridors and towards common landing points.
- Less disruption to the seabed and onshore areas.
- Minimising interactions with existing infrastructure and avoiding overlapping routes.
- Lower cost by sharing surveys, equipment, and construction efforts (e.g. installation vessels and trenching operations).
- Easier compliance with environmental and other regulations.

However, coordination also comes with risks:

- Possible delays or additional costs if projects are interdependent.
- Increased vulnerability to damage or failure resulting in security risks if assets are too close to each other.
- Challenges in accessing and repairing shared infrastructure.
- Potential risks due to interface management between multiple developers – delays, dependencies, commercial, regulatory and liability difficulties, etc – that would prevent the transmission developers from meeting their license obligations.

Once a cable route is chosen, considering other projects, the developer does not need to change it later to accommodate new third-party plans.

Design considerations

At the earlier stages of a project's development:

- Potential for shared marine survey campaigns.
- Potential for shared primary and auxiliary infrastructure onshore and offshore.
- Potential for shared cable corridors.

In the subsequent stages of a project's development:

- Restricted marine areas which limit space for cables or impose constraints on subsea routeing.
- Requirements for cable spacing for the projects under consideration and the availability of required seabed and landfall area.
- Relative timing and location of developments in the vicinity.
- Potential to minimise cable crossing.
- Potential for shared impact mitigation measures, subject to each project's consents obligations.
- Potential security and safety risks due to physical proximity of coordinated assets – risks of common failure modes (internal failures and external damages).
- Ease of access for repair and servicing.

References

- Proximity Study, The Crown Estate, 2012

03	Landfall area locations should meet the technical requirements of the overall project, while respecting both marine and terrestrial constraints, considering potential impacts on environment, community, as well as deliverability and economic efficiency.

Rationale

Offshore infrastructure makes landfall at various locations along the coastline of Great Britain. For electricity infrastructure, the general location of landfall is in the first place influenced by the technical need to provide transmission capacity. At the same time, other considerations, namely detailed technical design, environmental constraints, impacts on community, economic efficiency, deliverability and security of supply, are important in determining the landfall location.

Moreover, the coastline surrounding Great Britain is home to a diverse array of terrestrial and marine habitats and ecosystems, protected landscapes, archaeological sites, conservation areas, geological and physical features, alongside settlements, recreational amenities, as well as infrastructure and technology, such as coastal defences oil and gas pipelines and telecommunications cables.

Design considerations

- The primary technical need justifying the new development, and thus determining the wider region for the location of the landfall
- Location of feasible onshore landfall locations with reference to multiple marine and terrestrial spatial constraints, including local communities and tourism; environmental designations and features of conversation importance, historic environment designates sites and features of interest; suitable geology and topography as well as other existing or planned infrastructure. Consideration should also be given to availability of access roads and other enabling infrastructure and facilities.
- Availability of sufficient onshore space at the landfall location to host the required High Voltage Alternating Current (HVAC) or High Voltage Direct Current (HVDC) cables and other auxiliary equipment.
- Location of point of connection with available capacity for feed-in
- The offshore and onshore cable and their impacts on sensitive areas, local communities and the environment.
- Potential for applying mitigation measures as appropriate.

References

- Proximity Study, The Crown Estate, 2012

7. How to respond

How to respond to this consultation

How to respond to this Consultation

The National Energy System Operator (NESO) has published this consultation document to seek feedback on the content of this, the first iteration of the Principles.

The consultation is open to all individuals and organisations and will close at 11:59pm BST on Sunday, 26 October 2025.

Please submit your response using our online form: etdp-consultation response

We have included specific questions where we would particularly welcome your feedback. However, we would welcome other comments on the proposed Principles, and would request that they be provided with due consideration to the mission statement and purpose of the Principles.

Consultation Questions

1. Do you agree that the Principles are written in a clear and accessible manner?
2. Given the context of the mission statement, are there any guidelines for transmission design that you think are missing?
3. Which Principles are you supportive of and which do you disagree with and why?
4. Do the Principles promote transparency in decision-making about new transmission projects?
5. Are the Principles realistic and actionable for designers and users of the Principles?

8. Next steps

Next Steps

Following the close of this consultation, The National Energy System Operator (NESO) will review and analyse all responses received. The ETDP Working Group will then reconvene to consider this feedback before publication of a final version of the Principles in early 2026.

Once published, the Principles will undergo an initial review within the first year of implementation to assess their effectiveness and identify any necessary refinements.

It is anticipated that, subject to review by relevant policymakers, the Principles would be referenced in the National Policy Statement EN-5 – 'Electricity Networks National Policy Statement' in England and Wales, and compliment the National Planning Framework 4 in Scotland.

Subsequent reviews and revisions of the Principles will be undertaken in alignment with updates to the National Policy Statements and/or National Planning Framework, ensuring the Principles remain current and fit for purpose. These reviews will be overseen by a Working Group with similar representation to the current ETDP Working Group.

9. Legal Notice

Legal Notice

For the purposes of this report, the terms “NESO”, “we”, “our”, “us” etc. are used to refer to National Energy System Operator Limited (company number 11014226).

NESO has prepared this report pursuant to its statutory duties in good faith and has endeavoured to prepare the report in a manner which is, as far as reasonably possible, objective, using information collected and compiled from users of the gas and electricity systems in Great Britain, together with its own forecasts of the future development of those systems.

While NESO has not sought to mislead any person as to the contents of this report and whilst such contents represent its best view as at the time of publication, readers of this document should not place any reliance in law on the contents of this report.

The contents of this report must be considered as illustrative only and no warranty can be or is made as to the accuracy and completeness of such contents, nor shall anything within this report constitute an offer capable of acceptance or form the basis of any contract.

Other than in the event of fraudulent misstatement or fraudulent misrepresentation, NESO does not accept any responsibility for any use which is made of the information contained within this report.

10. Glossary

Acronym	Description
Air Insulated Switchgear (AIS)	Switchgear that uses air as an insulating medium to dissipate fault currents.
Centralised Strategic Network Plan (CSNP)	A longer-term strategic assessment of transmission network needs, primarily for the transfer of energy across electricity transmission, gas transmission, and hydrogen, initially to 2050 but with a rolling 25-year time horizon. It will assess options for achieving the net zero target and select optimal projects for a shorter term delivery, and a longer term range of potential projects for future delivery.
Department for Energy Security and Net Zero (DESNZ)	UK Government department focused on the energy portfolio, formerly part of the Department for Business, Energy and Industrial Strategy (BEIS). DESNZ is responsible for delivering security of energy supply, ensuring properly functioning energy markets, encouraging greater energy efficiency and seizing the opportunities of net zero to lead the world in new green industries.
Electricity Transmission Design Principles (ETDP)	The ETDP are a key recommendation outlined by the Electricity Network Commissioner Nick Winser, and discharged by the Transmission Acceleration Action Plan. These principles seek to provide greater clarity on the type of asset to be considered in different environments and to set out the core rationale and design considerations that shape the development of the electricity transmission system.
Environmental Impact Assessment (EIA)	A process that evaluates the potential environmental consequences of a project or development before it is approved.
Gas Insulated Switchgear (GIS)	Switchgear that uses gas (typically F-gas) as an insulating medium to dissipate fault currents. Can also be used for a Gas Insulated Busbar (GIB).
Global Warming Potential (GWP)	A measure of how much heat a greenhouse gas traps in the atmosphere over a specific time period, relative to carbon dioxide (CO_2).
Horizontal Directional Drilling (HDD)	A method of undergrounding cable for short sections to mitigate against challenging topography or other infrastructure obstacles.

Acronym	Description
High Voltage Alternating Current (HVAC)	Transmission voltages of 400 kV and 275 kV in England and Wales, and 400 kV, 275 kV and 132 kV in Scotland.
High Voltage Direct Current (HVDC)	Transmission voltage typically at ±320 kV or ±525 kV using direct current to transmit power over significant distances minimising transmission losses. An offshore High Voltage Direct Current (HVDC) transmission link comprises two onshore DC converter stations connected to separate nodes on the transmission network, along with two or three HVDC offshore cables connecting the two converters. Each of these converter stations is expected to occupy between 4- 5 Ha, which is approximately 8 times larger than a football pitch. It is important to note that not all offshore cables use HVDC technology; routes of a few tens of kilometers can use High-Voltage Alternating Current.
Main Interconnected Transmission System (MITS)	High-voltage electricity transmission network in Great Britain, specifically the 400 kV and 275 kV supergrid elements and, in Scotland, the 132 kV systems connected to them.
National Energy System Operator (NESO)	NESO is the independent energy system operator in Great Britain. Taking a whole system approach, NESO plan the electricity and gas systems and operate the electricity system to drive the transition to net zero.
National Planning Framework (NPF)	NPF sets out spatial principles, regional priorities, developments and planning policy for Scotland.
National Policy Statements (NPS)	Statutory documents published in accordance with the Planning Act 2008.
Offshore Transmission	Offshore transmission projects including bootstraps, OFTO connections, and interconnectors are all within the scope of ETDP.
Overhead Line (OHL)	A high voltage transmission circuit carried by lattice towers or wooden poles at 132 kV for Scotland.

Acronym	Description
The Office of Gas and Electricity Markets (Ofgem)	Ofgem is the government regulator for the electricity and downstream natural gas markets in Great Britain. Their principal objective is to protect the interests of existing and future electricity and gas consumers.
Security and Quality of Supply Standard (SQSS)	It sets out the criteria and methodology for planning and operating the National Electricity Transmission System onshore and offshore.
Strategic Spatial Energy Plan (SSEP)	The SSEP will spatially map the optimal mix and location of clean generation and storage to meet forecast demand, net zero targets, and security of supply for all consumers.
Supergrid	The supergrid refers to the high-voltage transmission network, primarily operating at or above 275 kV, that facilitates the long-distance transfer of electricity across Great Britain.
Transmission Acceleration Action Plan (TAAP)	The government's response to the Electricity Network Commissioner's report on accelerating electricity transmission network build. The Action Plan seeks to halve the end-to-end build time of electricity transmission network infrastructure, from 14 to 7 years.
Transmission Owners (TOs)	A collective term used to describe the three transmission asset owners within Great Britain, namely National Grid Electricity Transmission (NGET), Scottish and Southern Electricity Networks – Transmission (SSEN-T) and SP Transmission Limited (SPT).
Underground Cable (UGC)	A high voltage transmission cable originating onshore, including those whose routes are partly offshore. UGC make up approximately 5% of the existing transmission system in England and Wales. Most underground cables are installed in urban areas, where it is less practical to use OHLs.
Working Group/ ETDP Working Group	The group convened by NESO to develop the Principles, consisting of subject matter experts from the Great Britain Transmission Owners, UK Government, Scottish Government, Welsh Government, and Ofgem. The Planning Inspectorate also joined the group during the development of the Principles.

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