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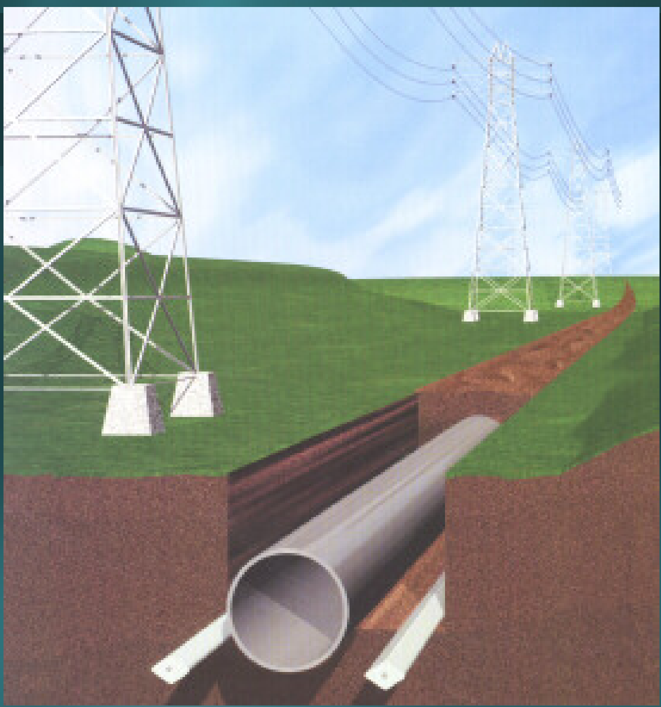

PowerWater

APA Gas Pipeline LFI Mitigation Review

March 2014

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1 Background

In 2012 the Australian Standards published an updated *Electrical Hazards on Metallic Pipelines* standard AS4853:2012. The previous version had been released in 2000. This has a substantial revision which has focused on a risk based approach to assessment using input data from more detailed analytical studies. The previous version was based on industry Rules of Thumb and relatively crude analysis techniques.

A major cause of Electrical Hazard is Low Frequency Induction (LFI) due to nearby power transmission and distribution lines. The quantification of LFI levels in real systems can be a complex task with many inputs. Invariably this needs to be done on a case by case basis. Generalisation of outcomes for a given configuration is generally not practical. The older standard endeavoured to generalise the analysis but failed to provide a useful assessment in most cases.

The new standard addresses this key issue by presenting a procedure which recommends a number of assessment levels. In the first level conservative criteria have been developed which can be used to test the system using limited input data to determine if further analytical assessment is required. If the system fails at this level, the second level of assessment requires a more intense analytical approach with a significantly increased data requirement. This analysis is very often conducted with the aid of software packages capable of modelling inductively, capacitively and conductively coupled electrical systems.

The third level of assessment is using the data determined from the second level as input to a structured and quantitative risk analysis in terms of the hazard to human beings and damage to equipment. There is also software available to assist in this Risk Based Assessment (e.g. Argon).

The APA pipelines were installed in the 1980's and 1990's which predates the original Electrical Hazards standard. Therefore mitigation of LFI very likely was not as thoroughly investigated as would be the case today. As well as being a safety hazard LFI can also potentially reach levels of several thousand volts where it can damage the pipelines insulating coating. This would have likely been considered when the pipeline was constructed with the mitigation strategy being to segregate (Insulated Joints) and earth the pipeline. Segregation restricts the parallel length of exposed pipeline and therefore as a consequence restricts the maximum induced voltage relative to the earth.

The purpose of the pipeline coating is to prevent galvanic corrosion. Damage to the pipeline insulation should be avoided since it increases the risk of corrosion.

High levels of LFI will coincide with ground faults in the power transmission system where substantial currents flow in a phase conductor which returns to the substation via the earth. When these fault events occur, the pipeline insulation can be stressed. In addition to this, personnel working on the pipeline's exposed parts can be subjected to high touch voltages between the pipeline and the remote earth. Because the pipeline is buried there are only exposed metal parts at:

- Scrapper Stations
- Isolation valve sites
- Cathodic Protection (CP) Sites
- Terminal Points.

APA have had a study conducted to assess the Safety Risks at the CP sites. This has been carried out by Geoff Cope and Associates (GCA) with the report being titled; *Katherine – Darwin City Gate – Channel Island Investigation of Induced Voltage Mitigation Requirements*. The purpose of this review is to examine the methodology, completeness, and correctness of the GHCA/APA study and also to evaluate the mitigation recommendations.

Active Cathodic Protection (CP) is utilised in these pipelines. The CP sites are the main focus of this study since there has been a recent upgrade of these systems. It is a requirement that the LFI hazard also be examined due to these changes. In any case as part of a Risk Management Plan it is now mandatory to have periodic reviews as indicated by the extract from the standard below.

> *Electrical hazard risk management is an ongoing process over the life of the pipeline and risk treatments require continuous management so that they remain effective. The hazard management plan shall be reviewed periodically to identify changes in the pipeline or power line that may change the electrical hazard and, if necessary, to revise the treatment design.*
>
> *The electrical hazard risk management plan shall specify the maximum review period. The period shall not exceed 5 years unless approved*

2 The Mechanism of Low Frequency Induction in Gas Pipe Lines

When the power conductor and the metal pipeline share the same space, magnetic flux originating from the power transmission system will link with the metallic pipeline and hence AC voltages will be induced in them as described in Figures 1 and 2. Mutual magnetic coupling exists between all the conductors of the power line and the pipeline.

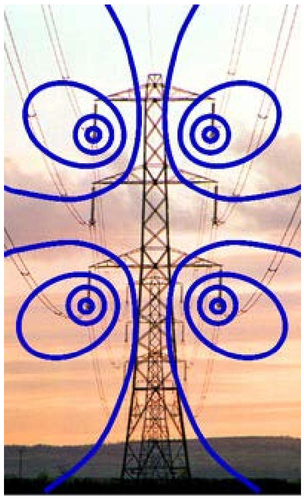

Figure 1: Magnetic Field Lines of Tension

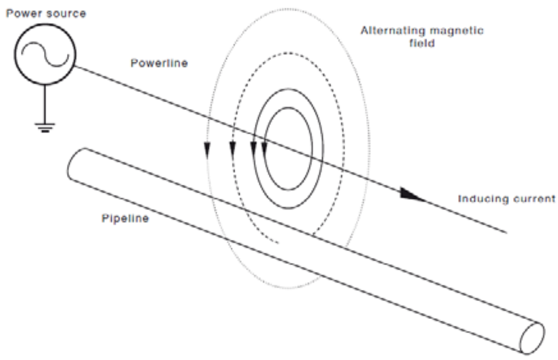

Figure 2: Magnetic Field Lines Linking the Pipeline

Under normal steady state conditions all the phase conductors carry alternating currents. In a 3 phase system there is time (Phase) displacement between the current waveforms. Each current produces closed magnetic field lines which link the conductor. The vector summation of these fields at the location of the pipeline gives a resultant field which then acts to induce a voltage. The magnetic field level reduces as the pipeline is moved away from the power transmission line. Typically at a distance of 100m the steady state levels are diminishing to a very low level as illustrated in Figure 3. This strong reduction is due to both the distance and the phase relationship of the currents and diminishing field levels as we move away from the conductors. For a balanced 3 phase system the magnetic fields will sum to zero at any equidistant location from all the conductors. At a point far from the transmission line the distances are almost the same and therefore there is a high degree of field cancellation. The conductor arrangement for a typical Transmission Line Tower is shown in Figure 4.

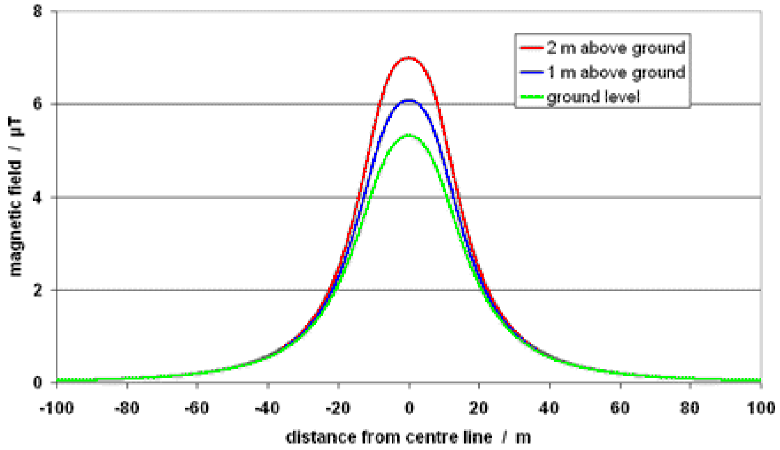

Figure 3: Magnetic Field Strength as a function of distance from a Power Transmission Line (Typical)

This is not true under fault conditions where high levels of current typically flow from one phase conductor to the tower's metal structure and then splits between aerial earth wires and the ground. Due to the impedance of the aerial earth wires a significant proportion of the current returns back via the earth path at the faulted tower. Further to this a proportion of the current that does flow back along the aerial earth wires will be diverted to the earth at the next adjacent tower and all the towers in the return path due to there being parallel paths as illustrated in Figure 5. The diverted current diminishes as the displacement from the fault increases.

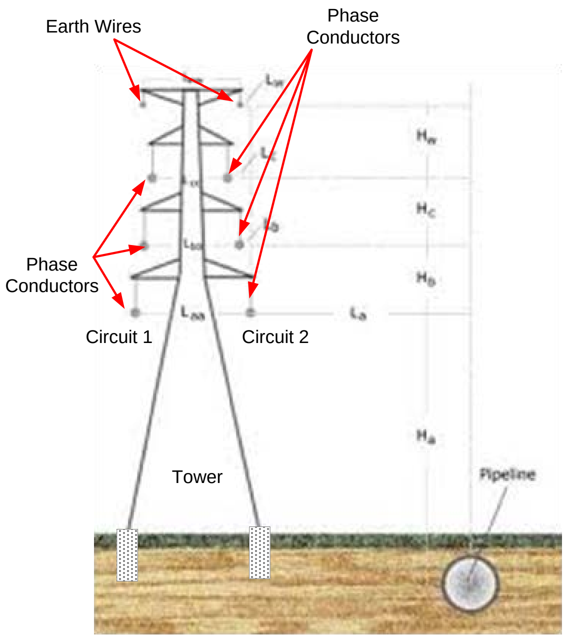

Figure 4: Conductor arrangement for a typical Transmission Line Tower

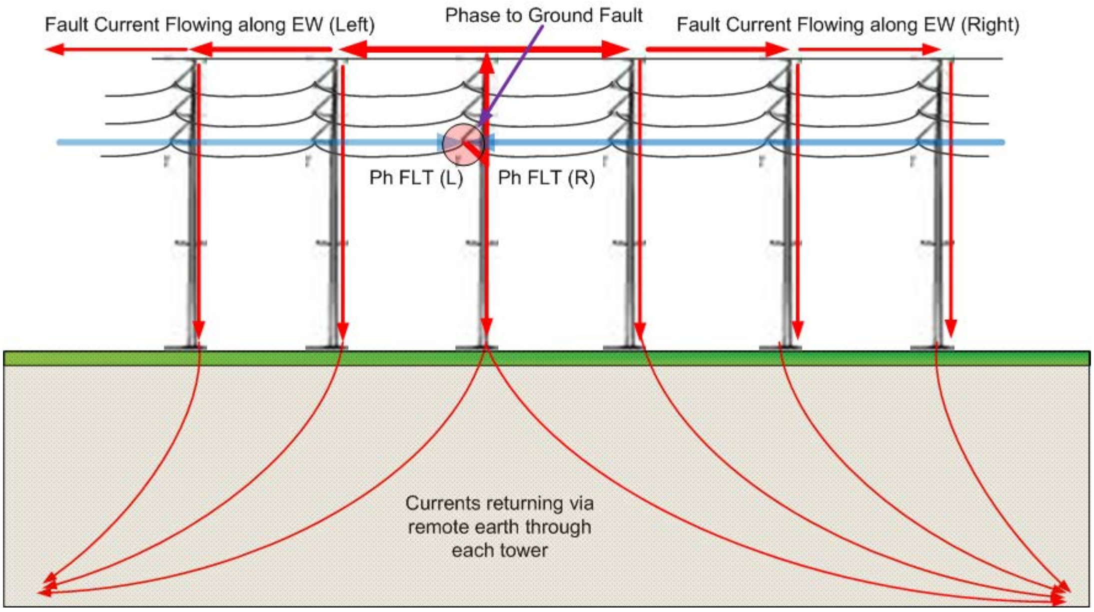

Figure 5: Transmission Line Fault Current Paths

The end result is a significant proportion returns via the earth. This results in significant increase in LFI levels due to the strong imbalance of currents. If the current was to return completely along the earth wire, due to it being relatively close to the phase conductor there would be a high level of magnetic field cancellation and therefore lower levels of LFI.

The significant proportion of current which returns via the earth is characterised to flow through equivalent mirror conductors beneath the earth. This mathematical representation was developed by John Carson early in the 20th century and revolutionised the analysis of magnetic coupling in earth return systems. Consider the above ground conductors i and k as illustrated in Figure 6. Once the image conductors are included it is relatively simple to quantify the magnetic coupling of conductor k on conductor i. In this illustration the earth is considered to be perfectly conducting in which case the fictitious image conductors are of equal depth below the surface as the real conductors are above. In reality the earth is not perfectly conducting and the image conductors are at a much larger depth. This depth can be calculated and is a function of the earth resistivity measure in Ω-m. Higher earth resistivity gives rise to image conductors which are considered to be many 100's of metres below the surface.

The importance of these image conductors is that they provide shielding action in terms of LFI. When they are closer to the phase conductor they provide a cancelling effect (Currents are in opposite directions). This is the same mechanism which occurs with the real earth wires run on top of the tower. In both cases they are said to provide shielding.

This shieling action of the fictitious subterranean conductors improves when the earth resistivity is low. In areas where earth resistivity is high the influence of magnetic field extends further from the source conductors and therefore the profile shown in Figure 3 becomes broader. The LFI exposure zone also becomes correspondingly wider. Therefore in low resistivity earth a transmission line to pipeline separation of 1000m might be considered a long distance. The result being that LFI levels would be low and therefore the effect in terms of induced voltage for a given exposure length would be relatively low. The same is not true in high resistivity soil where a separation of 1000m may still present a significant issue.

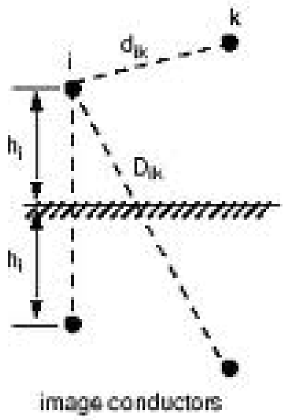

Figure 6: Image Conductor Concept used in Carson's Analysis

In summary the key parameters which govern the LFI voltage levels in a pipeline are as follows:

- Transmission line to pipeline separation
- Transmission line currents (Fault Current to earth is the main issue in terms of safety)
- Earth Resistivity
- Transmission geometrical configuration in terms of earth conductors
- Parallel exposure length of the transmission line with the pipeline
- Conductive earthing of the pipeline itself
- Self-Impedance of the pipeline.

In terms of the parallel exposure length it is important to understand that if there is an angular relationship between the transmission line and the pipeline that the LFI level reduces and is zero if the two systems run at 90° to each other. Normally this is taken into account in commercial analysis software.

Conductive earthing of the pipeline can be intentional and also non-intentional. The pipeline is normally insulated from the ground by a Polyethylene jacket. This is required to prevent DC Cathodic Protection currents leaking to the ground. Nonetheless there is a finite resistance which allows the flow of LFI current. For AC currents there is also a capacitive path which is a function of the dielectric constant of the jacket and the resistivity of the surrounding earth. This conductive and capacitive coupling affects the level of the LFI voltage relative to earth at each point along the pipeline due to the flow of current and voltage drop across the self-impedance of the pipe line.

In addition to this the pipeline design engineer will normally segment the pipeline and ground various locations to restrict the voltage levels and therefore electrical stress applied to the insulating coating. If the voltage across the coating becomes too high in response to power system fault it may be punctured which will then have a detrimental effect on the operation of the Cathodic Protection system. It would be normal practice to at least ground each end of the pipeline. Grounding is achieved through buried conductive arrays which strive to reduce the resistance measured to the remote earth typically to a few ohms. The remote earth is a fictitious location which is considered to be equal-potential in terms of currents flowing in the earth. Figure 7 describes the use of earthing to reduce pipeline voltages.

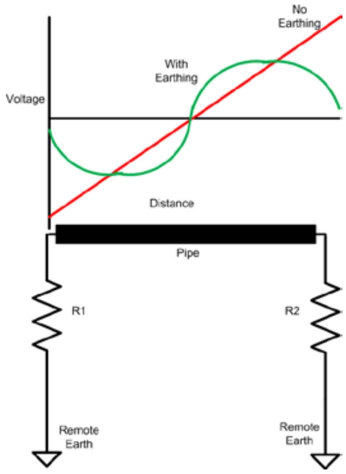

Figure 7: LFI Voltage profiles for unearthed and earthed pipeline

With the pipeline open circuit at each end the voltage will be high but with opposite phase at these points. In the centre it will be zero if the network (including induction levels) is homogenous and perfectly balanced. In practice this is never the case and the voltage profiles can vary widely, normally software programs are required to calculate accurate voltage profiles.

When earthing is applied the voltage is reduced due to the flow of current in the impedance of the pipeline itself. It should be noted that the earths are normally applied through devices which pass AC currents at the elevated voltage levels which arise when Transmission line faults occur but block the lower DC voltages associated with the Cathodic Protection system.

Another issue related to pipelines exposed to faulted transmission line towers is Earth Potential Rise (EPR). The EPR issue has not been examined in the report under review, but for completeness it is briefly discussed as follows. When a transmission line phase conductor has a fault to a tower (or earth wire) as discussed previously high levels of current will flow to ground through the concrete footings of the tower. This current will radiate out from the tower as it flows to the remote earth. There will be a voltage gradient in the earth which can be measured at its surface. This voltage gradient is illustrated in Figure 8. This gradient directly gives rise to a step potential on ground. If the pipeline is running close (Typically less than 20m separation) to the tower it can be within the EPR zone. If the metal pipe is considered to be at the Remote Earth potential then the coating will be exposed to high electric stress. In some cases this can combine with the LFI to produce larger electric stress levels. The analytical assessment then becomes more complex. Some software packages are able to execute the necessary calculations to make this assessment. In this particular study there does not appear to be any areas where the pipeline is in sufficiently close proximity for EPR to be a concern.

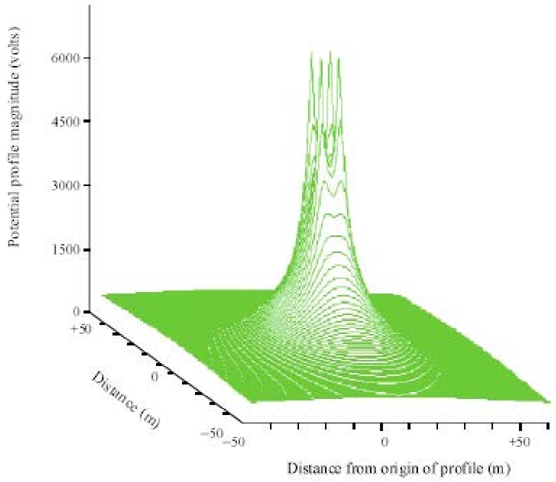

Figure 8: Example of earth potential rise profile during a tower fault to earth

The final item that needs to be discussed in relation to LFI is the assessment of the fault currents in the transmission system to which the pipeline is exposed. Accurate determination of the currents in each section of the shared corridor is important to obtaining an accurate result for the LFI voltage profile. Typically for a meshed feeder, currents will flow in both directions moving away from the fault. As discussed previously a proportion of the current flows to the ground and another proportion through the earth wires in both directions away from the fault. There is further diversion of current to the ground at each tower; however this effect diminishes with distance from the fault. A simplified system is shown in Figure 9.

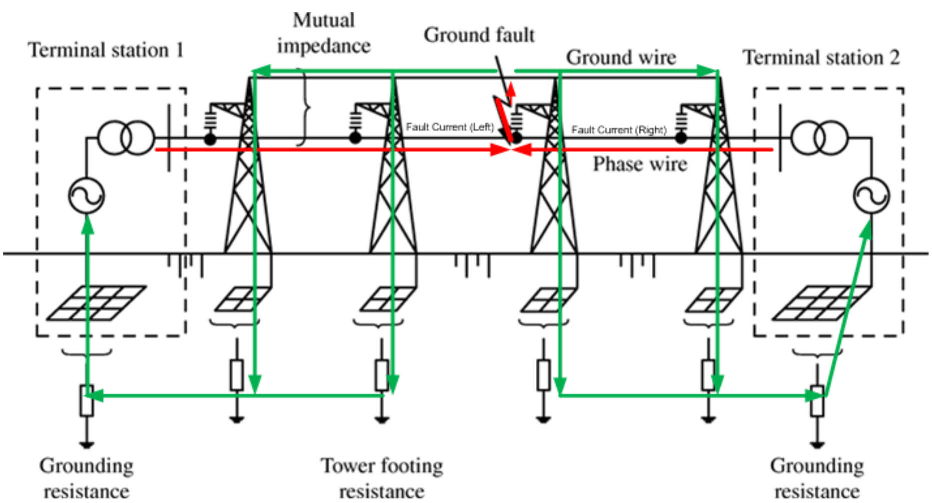

Figure 9: Earth fault current path illustration

The fault currents flowing from the left and right and the diversion to the ground needs to be determined through the shared corridor. The actual fault current is also a function of the position in the line where the fault occurs. The final pipeline induced voltage profile is a function of many parameters as follows:

- Transmission line configuration
- Tower geometry

- Fault position
- Substation fault levels
- Separation/exposure length profile
- Pipeline dimensions and characteristics
- Earthing both intentional and non-intentional.

In order to conduct a comprehensive analysis it is generally necessary to consider faults at different points in the line to determine the worst case LFI profile in the particular pipeline. For example on a radial distribution feeder (Feed from one end with only loads distributed over its length) the highest fault level will be at the supply substation however the pipeline exposure length will be least at this point. At the other extreme the fault current at the end of the line may be as little as 25% of that at the substation, but the exposure length would be much longer. An appropriate software package is required to make an accurate assessment of different scenarios. In some software packages the power systems analysis and the LFI assessment is integrated. But in others a separate load flow program is required to determine the fault levels and these are input to the LFI assessment tool. In this case the fault current distribution, (Left/Right) needs to be applied.

Figure 10 shows an example of the fault current profiles for a transmission line between two substations ‘X’ and ‘Y’. This example is taken from the Electrical Hazards on Metallic Pipelines Standard. The fault level at substation X contributed by X is 10kA. The fault level at X contributed by Y is 0.8kA. The total fault current at X will be approximately 10.8kA. At Y the fault current contribute by Y is 4.5kA and that contributed by X is 1.7kA. The total fault level at X is 6.2kA. The fault level in the middle of the line is approximately 6kA with contribution from each feed being roughly equal at 3kA. When the LFI is assessed for a fault in the middle of the line the left and right currents would need to be set at 3kA. Relative to the pipe these currents are in opposite directions and therefore the resultant induced voltages oppose each other. The final voltage profile would then be dictated by this plus the separation profiles and exposure lengths.

The preceding discussion is aimed at giving an overview of the mechanisms and important parameters related to the assessment of LFI. It should be appreciated that in real systems the analysis is complex and the results are not always intuitive.

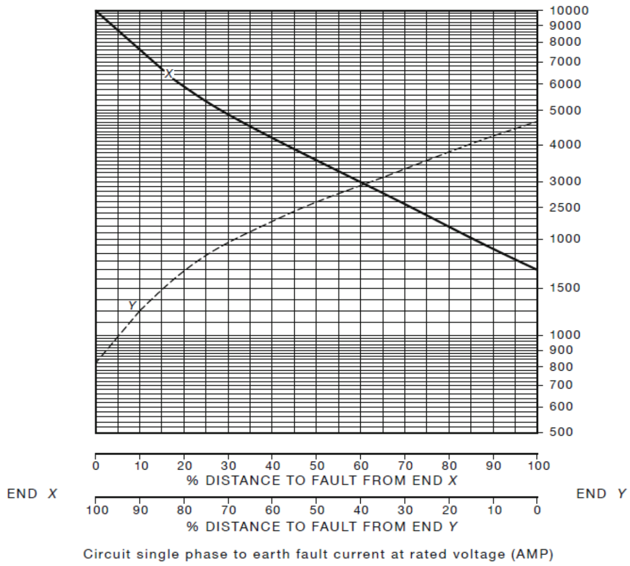

Figure 10: Example of fault current contribution profile for a mesh feeder.

3 LFI Assessment Methodology as required by Australian Standard (AS) 4853:2012

The Electrical Hazards on Metallic Pipelines standard essentially takes a risk based approach to managing the LFI problem. The Hazards are electrical shock to personnel and physical damage to the asset due to overvoltage stress on the insulating coatings. In addition to this there is a hazard associated with low level LFI causing corrosion of the pipeline. Historically it was thought that because alternating current reverses periodically there would be no net corrosion effect. However due to irreversibility of the chemical reactions corrosion can occur due to AC current under certain conditions.[1] It is thought that AC currents concentrating at existing Holidays, if of sufficient magnitude, can give rise to corrosion of the metal. Figure 11 shows typical damage due to AC corrosion. The standard recommends that the steady state AC voltage be maintained below 4VAC in low resistivity soils (<25 ohm-m). This is a steady state voltage which whilst being very low still has the capacity to cause irreversible chemical reactions which bears some similarities to AC rectification. It is only the steady state induction which is relevant since whilst under fault conditions the levels are much higher they are only present for relatively short periods.

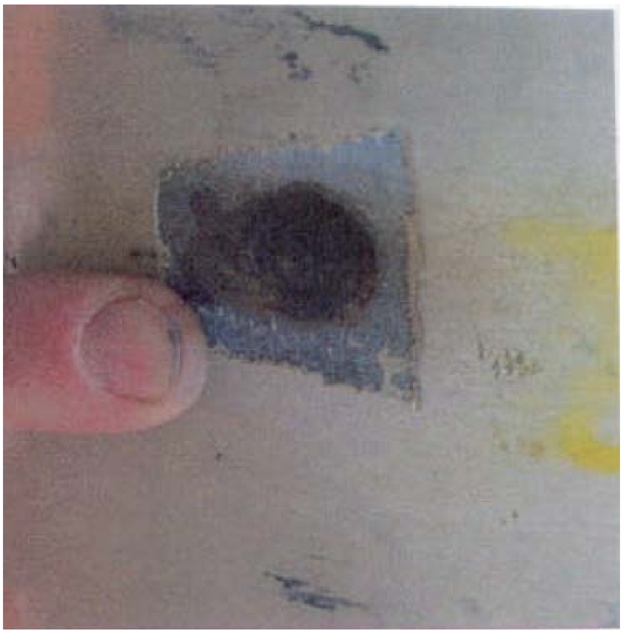

Figure 11: Example of the action of AC Corrosion

Whereas it is possible to model the system under steady state conditions in this study the levels were actually measured at the CP test points. These voltages are measured between the pipeline and the remote earth.

AC corrosion represents a hazard to the asset and is an issue in shared corridors with the transmission line operating under normal steady loading. The shock hazard mainly exists to workers and the public when the transmission lines undergo a phase fault to earth. However under steady state the LFI voltage levels could still be significant given maximum allowed levels will be lower due to continuous exposure. (There is also a potential for increased LFI in the case of a balanced 3 phase fault but the levels are considerably less).

[1] AC induced corrosion on onshore pipelines, a case history, Roger Ellis Shell UK, Stanlow, Pipeline Manager

The standard is based on a multiple stage risk based approach. In the preliminary stages of the assessment a crude analysis is conducted which decides if the system will be safe based on very conservative criteria and parameters. Figures 12 and 13 show the criteria for both Transmission and Distribution lines. Very conservative assumptions have been made as follows:

- In regards to shielding provided by aerial earth wires
- System Fault levels
- The amount of current which is diverted to the earth return path.

The maximum exposure length is then a function of earth resistivity and separation. For example in a transmission system the maximum exposed length of pipe line would be 100m for a separation of 20m and an earth resistivity of 1000 ohm-m.

TABLE 4.4

CONSERVATIVE EXPOSURE LENGTH FOR PIPELINES SUBJECT TO LFI FROM TRANSMISSION POWER LINES

Power line to pipeline separation (m)	Exposure length (m)		
	100 Ω.m	500 Ω.m	1000 Ω.m
5	95	82	78
10	110	93	87
20	127	106	100
50	165	131	120
100	210	160	145
200	290	202	178
500	500	310	260

Figure 12: Conservative assessment tool used for Transmission Lines from AS4853:2012

TABLE 4.2

CONSERVATIVE EXPOSURE LENGTH FOR PIPELINES SUBJECT TO LFI FROM DISTRIBUTION POWER LINES

Power line to pipeline separation (m)	Exposure length (m)		
	100 Ω.m	500 Ω.m	1000 Ω.m
5	180	160	150
10	210	180	170
20	240	200	190
50	310	250	230
100	400	300	280
200	550	390	340
500	950	600	500

Figure 13: Conservative assessment tool used for Distribution Lines from AS4853:2012

In many cases the shared corridor will fail the initial assessment which then means that a more intensive analysis using more input data needs to be undertaken. Figure 14 shows a flow chart of the overall process. The zones of interest would be based on the initial superficial assessment and a site visit would normally be required to collect all the required data.

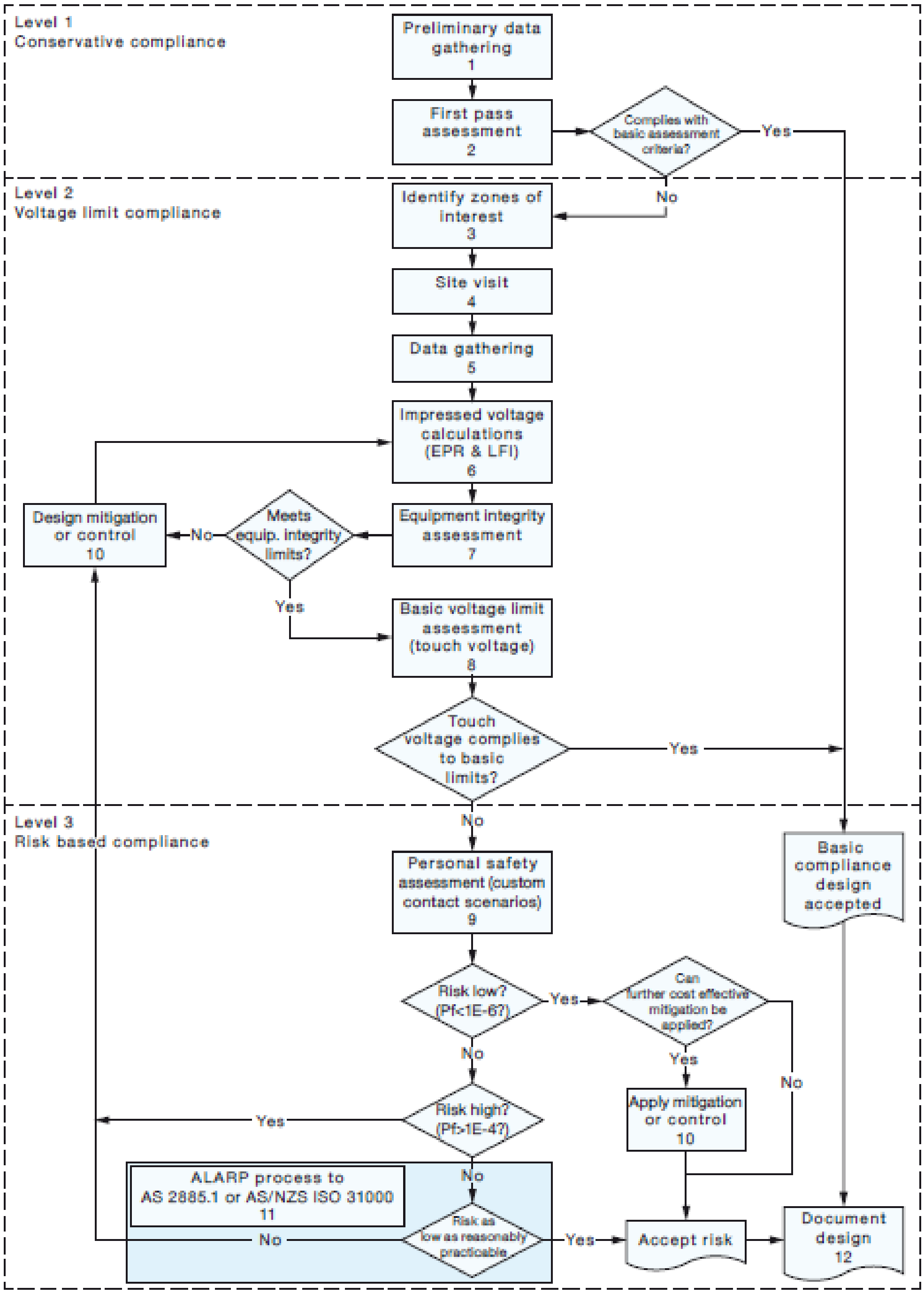

Figure 14: Electrical Hazard Design Process.

In the ideal case all the data required to conduct a more intensive study would be readily available, however in reality this will never be the case and invariably a site visit is required. The site visit also is important in terms of verifying the data that has already been obtained. During the site visit and data gathering phase the following items are considered:

- Soil type and resistivity
- Transmission Line to Pipeline separation profile

- Transmission line conductor geometry (Construction Drawings)
- Exposure length and relative angular orientation of the pipeline
- Earthing points
- Transmission or Distribution system protection details
- System Fault level profiles if available.

In the case of the system fault levels the power authority should have this data from load flow simulations.

Once all the input data is available it would be carefully entered into a software package which is capable of calculating the magnetic coupling between the pipeline and the transmission line. The known fault currents would be used to calculate the LFI voltage levels given the pipeline self-impedance and any grounding resistances. These calculations can also be made manually using the guidelines provided in the standard.

The equipment integrity can then be assessed under fault levels. This includes maximum voltage levels across the pipes insulation coating and insulating joints at valve and scrapper stations. Typically insulating joints are rated at 5000Vac maximum and the coating is rated at 10000Vac.[2]

The steady state LFI which is relevant to AC corrosion can generally be assessed using the same software or similar calculations. In this case it is important to obtain from the Power Authority the maximum phase unbalance that is likely to occur. Ideally in 3 phase systems there should be balanced phase currents. In a Transmission system this is generally the case, but in a Distribution system unbalances are more likely to exist.

The electrical safety hazard should normally be evaluated under both steady state and fault conditions. Under steady state the LFI levels will likely be very low (<15Vac), however because it is continuous lower limits will apply. The LFI under fault conditions is much higher but the limits are corresponding higher due to the short duration of the fault. Protection systems will normally disconnect the power to the faulted feeder in a relatively short period to prevent excessive damage to the transmission equipment. The type of protection and its operating time is therefore important in assessing the allowable levels of LFI through a Probabilistic Risk Analysis. Transmission Systems typically have short protection operating times and also have lower probability of faults. Therefore the allowable LFI voltage limits will be correspondingly larger based on a statistical analysis of the Risk. In contrast Distribution lines are considered to be less reliable and also typically have longer protection operating times therefore voltage limits will tend to be lower.

In the Quantitative Risk analysis process the contact scenarios' contact frequency and the fault frequency need to be considered. Figure 15 shows the Contact Scenario table from the standard. For example for CP test points on a pipeline in a shared corridor with a transmission line the contacts annually would be expected to be 250/year. The fault duration is expected to be 0.2seconds and the fault frequency can be taken as 1.5/year. The maximum tolerable touch voltage between the pipeline metallic parts and the remote earth will be 540Volts. This assumes a probability of a fatality of less than 1 in 1 million.

[2] AS/NZS 4853:2012 Electrical Hazards on Metallic Pipelines

CONTACT SCENARIOS THAT AFFECT PIPLELINE OPERATORS

Contact scenario	Contacts annually	Fault frequency	Touch voltage for $P_{\text{fatality}} \le 1 \times 10^{-6}$
Valve operator— Gas pipeline, distribution power line	5 5 min per contact (primary and secondary mains) 10% of work in the exposure zone subject to EPR and/or LFI	10/y 1 s in duration (distribution power line)	≤ 70 V
Valve operator— Gas pipeline, transmission power line		1.5/y < 0.2 s	< 500 V
Valve operator— Water pipeline, distribution power line	5 60 min per contact (primary and secondary mains) 10% of work in the exposure zone subject to EPR and/or LFI	10/y 1 s in duration (distribution power line)	≤ 58 V
Valve operator— Water pipeline, transmission power line		1.5/y 0.2 s in duration	≤ 220 V
CP Test points— Distribution power line	250 5 s per contact (10% of work in the exposure zone)	10/y 1 s in duration (distribution power line)	≤ 75 V
CP Test points— Transmission pipeline and power line		1.5/y 0.2 s in duration (transmission power line)	≤ 540 V
CP Test points— Transmission pipeline and power line (reduced contact)	25 5 s per contact and 10% of work in the exposure zone	1.5/y 0.2 s in duration (transmission power line)	≤ 880 V

Figure 15: Contact Scenarios for Operators

Figure 15 applies to operators; however similar tables have been presented for the Public, Maintenance Staff and Construction Staff. All workers are assumed to be wearing safety footwear which increases the electrical resistance of the potential path which may result in electric shock. The current is consequently reduced. Figures 16 to 18 show the tables for the other three categories. It is the operator category which is the focus in this review since these are the personnel making measurements at CP points on a regular basis and therefore are exposed the potential shock hazard.

There is an '*Argon*' software package is available free of charge to assist in the Quantitative Risk Analysis. This '*Argon*' software has been used by Geoff Cope and Associates (GCA) to assess the Katherine Off-take compound voltage levels under power line fault conditions. It is an alternative to using the tables and provides more flexibility in configuring the input data for each scenario.

CONTACT SCENARIOS THAT AFFECT THE PUBLIC

Contact scenario	Contacts annually	Fault frequency	Hazard voltage
CP test points, scour valves, regulator pits			
Metallic lid—Step voltage. Pipeline earthed by surge diversion devices	100 5 s in duration	10/y 1 s in duration	≤1700 V
Scour valve—Touch voltage	10 5 s in duration	10/y 1 s in duration	≤120 V
Playgrounds, sporting fields			
Contact with air valve on water main—Touch voltage	20 15 min duration	10/y 1 s in duration	≤50 V (≤310 V provided physical controls (e.g. asphalt) are used)

Figure 16: Contact Scenarios for the Public

CONTACT SCENARIOS THAT AFFECT CONSTRUCTION WORKERS

Contact scenario	Contacts annually	Fault frequency	Touch voltage for $P_{fatality} \leq 1 \times 10^{-6}$
Construction (new gas pipeline)	200 2 s per contact 100% jobs in the exposure zone Assumes that once blast cleaned, contacts are infrequent, welder insulated and wrapping insulated. Wearing gumboots (conservatively assume safety boots) and gloves	2/y 1 s in duration (distribution power line)	≤ 110 V
		1.5/y 0.2 s (transmission power line)	≤ 660 V
Construction—Tee-off from long exposed gas pipeline	0.2 jobs/y 1 h per job (100% jobs in the exposure zone) Assumes that the job includes manual cutting, (1 h on big jobs), infrequent tasks, wearing gumboots (assume safety boots) and gloves	2/y 1 s in duration (distribution power line)	≤ 110 V
		1.5/y 0.2 s (transmission power line)	≤ 600 V

Figure 17: Contact Scenarios for Construction Workers

CONTACT SCENARIOS THAT AFFECT PIPELINE MAINTENANCE WORKERS

Contact scenario	Contacts annually	Fault frequency	Touch voltage for $P_{fatality}$ $\leq 1 \times 10^{-6}$
Maintenance—Leak repair on water pipeline – Repair clamp (temp) or weld patch	5 2 h total time Based on 5% in contact (= 6 min), infrequent tasks, wearing gumboots (assume safety boots) And 5 jobs/y, 6 min per job (say 100% jobs in the exposure zone)	2/y 1 s in duration (distribution power line)	≤ 95 V
		1.5/y 0.2 s (transmission power line)	≤ 510 V
Repair clamp (temp) or weld patch	2 h total time Based on 5% in contact (= 6 min), infrequent tasks, wearing gumboots (assume safety boots) and gloves And 2 jobs/y, 6 min per job (say 100% jobs in the exposure zone)	2/y 1 s in duration (distribution power line)	≤ 110 V
		1.5/y 0.2 s (transmission power line)	≤ 595 V
Maintenance—Leak repair on gas pipeline – Repair clamp (temp) or weld patch	Brief contact (rarely) = 10 s, very few leaks, wearing gumboots (assume safety boots) and gloves 1 job/y, 10 sec per job (say 100% jobs in the exposure zone)	2/y 1 s in duration (distribution power line)	No limit (This activity is rarely performed and therefore contact duration is too small for P_f to be of concern.)
		1.5/y 0.2 s (transmission power line)	No limit

Figure 18: Contact Scenarios for Maintenance Workers

4 Changes in the AS 4853 Standard, between the 2000 and 2012 Versions

In the previous version of the standard, the touch voltage limits were fixed and there was no flexibility in terms of adaptation to different contact scenarios and fault scenarios. It was not based on a Risk Methodology and therefore was not flexible in terms of setting limits. There were some crude guidelines for calculating LFI levels which were structured to provide very conservative results. The beneficial effect of shielding was ignored. There were no guidelines on the calculation of actual fault levels within a system and therefore worst case sub-station levels were normally used. This approach is much the same as the first stage assessment in the new standard and as such very often yielded negative results. In some instances this led to unnecessarily demanding mitigation measures.

Essentially the difference in the new standard is that if the system fails on the conservative assessment a more detailed and Risk Based analysis is triggered. The Risk based assessment is a structured process to assess the likelihood of an electrical hazard being present on a metallic pipeline, and the methodology by which the risk level associated with the hazard is calculated, and the effectiveness of methods to reduce the risk to an acceptable or in the ALARP region to a tolerable level is provided.

In some cases the results of this analysis could show that the mitigation measures can be moderated. Mitigation measures for operators which could be considered as an alternative to major works on the pipeline infrastructure are as follows:

- Gloves
- Asphalt
- Earth grid with gas discharge tube. For personnel protection, the gas discharge tube
- Firing voltage should typically be 20 V.

In the case of the earth grid the objective is to create an equipotential ground area in which the personnel are working. The earth grid for the higher AC voltages that occur during power line faults is effectively connected to the pipe. The person standing on the ground with the earth grid beneath therefore sees very little potential difference when touching the pipe. There will however likely be quite high voltage gradients in terms of step potential generated at the boundary of the grid and the surrounding earth. For low AC voltages and DC voltages the grid is electrically separated from the pipe by special isolators (Kirk Cells or similar). This prevents interference with the cathodic protection system and therefore prevents increased corrosion rates of the earth mat and the pipeline. Typically these isolators will conduct when the AC voltage exceeds 2Volts and therefore will afford some additional earthing to the pipeline. However the resistance of the grading ring to the remote earth will not be very low and therefore the benefit is limited. The main objective of the grading ring is to afford protection to personnel against the risk of electric shock whilst measurements are being conducted at the test points. They will have only a marginal effect on lowering AC voltages on the pipeline as a whole.

5 Objective of the APA Study Scope

The objective of the APA study scope was to review the current Cathodic Protection sites in terms of safety to personnel and assess the potential for AC corrosion in the pipeline system. Specifically the Darwin City Gate to Katherine, Darwin City Gate to the Channel Island Power Station and the Katherine Lateral off-take were considered. All of these have parallel running transmission and distribution lines for portions of their length. They have existing CP measurement points distributed along their length at which AC LFI voltages can be logged. The recording of these voltages over a 20hr period was one of the tasks undertaken by Geoff Cope and Associates (GCA). The levels on each pipeline were recorded simultaneously using multiple recorders.

The other objective of this study was to assess the safety in terms of Electrical Hazards due to LFI at accessible points along the pipelines. The most common accessible point will be the CP test points. However there is also an off take on the main gas pipeline at the Katherine lateral, scrapper stations at Helling and Ban Ban Springs. There is another off take at Pine Creek for a Gas Turbine Power Station. Additionally there are CP injection points at various locations. Figure 19 shows the physical system under study including pipelines, transmission lines, substations and power lines. Figure 20 shows the gas pipeline schematic diagram of the system under study.

Of most concern are the CP test points which have connections to the pipeline and are used for measuring pipeline voltages on a routine basis. Under steady state conditions there will be relatively low voltage present at these points, however under fault conditions the level is much higher due to the increased transmission line currents and the inherent unbalance of the earth fault condition. It is possible to have, momentarily, voltages in the order of thousands of volts at these points. The duration of the faults is restricted by the operation of the power systems protection equipment. For a transmission system (132kV) typical operating times will be less than 300msec. However in radial distribution systems the fault interruption tine can extend to 1 second or more. This time needs to be taken into account when assessing the effect of the shock hazard.

As part of the scope, Geoff Cope and Associates (GCA) have modelled the shared pipeline and transmission line corridor using AC Predictive and Mitigation Software developed under the auspices of the *Pipelines Research Council International* and distributed by *Technical Toolboxes Inc, USA*. This software has been widely used for AC mitigation calculations and design for the pipeline industry. Figure 21 shows a brochure for this software. The main output of this software is voltage profiles throughout the shared corridor. This data can then be used to assess the human safety hazard level. The results can also be used to quantify the electric stress levels for the pipeline insulation under fault conditions. It has not been used this way in this study.

The earth resistivity is an important input for the LFI modelling and as such one of the tasks in the GCA scope was to conduct measurements. This was done at several sites but was not a comprehensive survey of the complete route. Since soil resistivity changes with location in order to obtain accurate results it needs to be assessed along the extent of the route. GCA measured the earth resistivity at a number of locations but the survey was not comprehensive. Estimates based on the actual measurements combined with local knowledge were used in the final model formulation.

It should be noted that pipe coating stress due to EPR was not part of this study. However strictly speaking according to the standard it needs to be addressed. Our understanding, based on our desk top survey of the routes, is that it is unlikely that there are any transmission towers or poles that are sufficiently close to the pipeline to present a significant EPR risk.

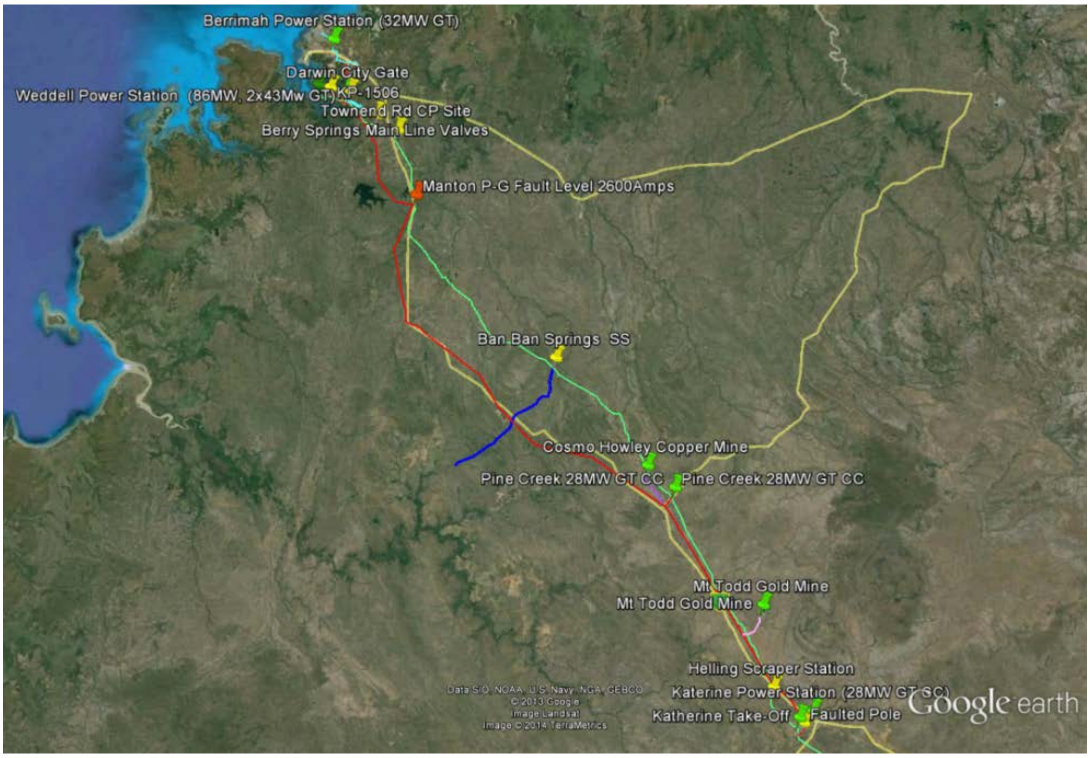

Figure 19: Transmission Lines and Pipelines for this study

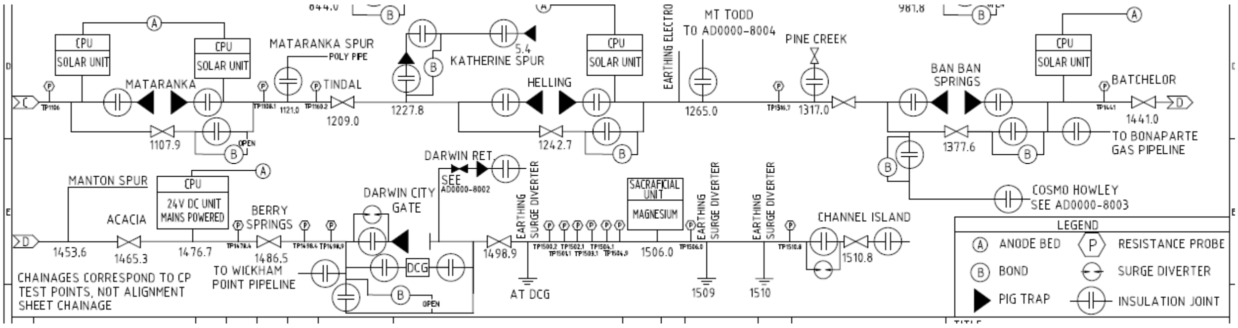

Figure 20: Schematic diagram of the Pipe Line in the study area

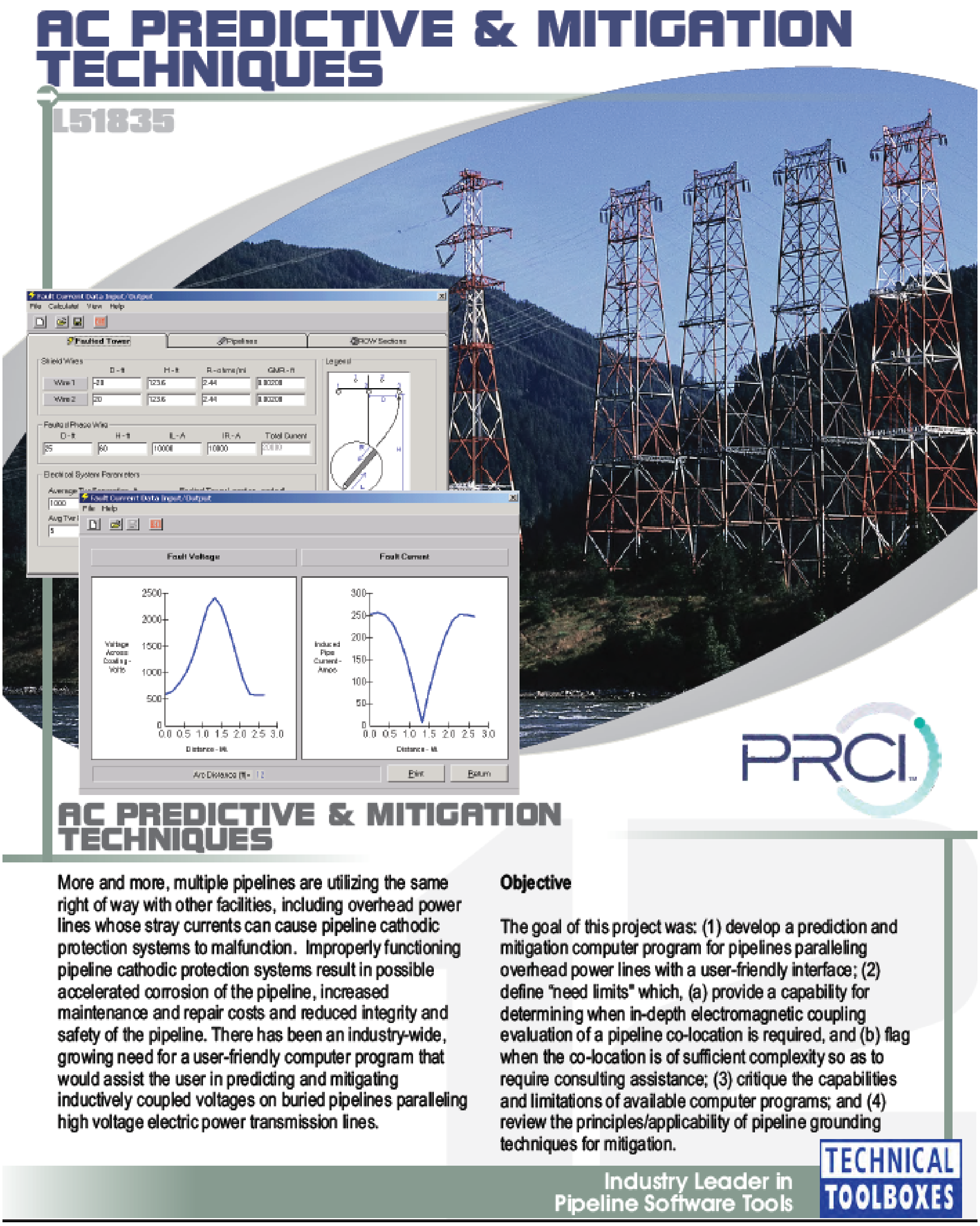

Figure 21: PRCI LFI analysis software toolbox

6 Review of the Study input Data

GCA was responsible for gathering all the required data for input into the model. Table 1 summarises the data which would normally be required for a shared corridor LFI assessment model.

Table 1: Pipe LFI Study Input Data Set

Data Input Description	Function of the Data	Source	Comment
Pipeline Route	Reference point for model	Construction Drawings	Can be overlayed with the TX line route in Google Earth. Accuracy is important where the separation is less than 50m
Transmission line Route in relation to the pipeline (Profile of separation and relative angle)	Calculation of the electromagnetic coupling	Construction Drawings	Separation can be determined from overlayed routes. Needs to be accurate at small separations. Angles which are not parallel will reduce the induction
Earth Resistivity (Profile)	Calculation of the electromagnetic coupling	Measurement Survey	GCA conducted measurements in some locations but there was not a complete survey. It can be specified Tower by Tower in the GCA model
Current pipeline earthing locations and resistances	Calculation of the pipeline voltage profile based on electrical network equations	Construction Drawings	GCA both measured and estimated these values based on experience
Locations of pipeline insulated joints	Sets the boundaries for the electrical network calculations	Construction Drawings	Information obtained from APA Schematic
Location of major pipeline equipment valves/scrapper stations, take-offs	Location of assessable assessment points	Construction Drawings	Information obtained from APA Schematic
Pipeline diameter and wall thickness.	Determines the pipeline self-impedance and coupling to other conductors	Construction Drawings	From APA Data. GCA software may contain data for standard pipes.
Pipeline coating thickness and resistivity	Influences the pipeline distributed leakage impedance to ground	Pipe Manufacturer	This is quite an influential effect in pipelines with poor or no other periodic earthing.
Pipeline Steel Resistivity and Magnetic Permeability. (GMR if possible)	These variables mainly influence the self-impedance which affects the circulating current	Pipe Manufacturer	This data may be inbuilt to the modelling software, otherwise the pipe manufacturer should supply or they are measured.
Transmission Line Phase Conductor Details (Diameter, GMR, DC Resistivity)	Determines the TX Line self-impedance and coupling to other conductors	Power Authority	The GCA software does not require this data since the phase fault currents are entered and are forced.

Data Input Description	Function of the Data	Source	Comment
Transmission Line Earth Wire Geometry. (X,Y,Z)	Determines the TX EW self- impedance and coupling to other conductors	Power Authority	The GCA software uses the GMR to calculate the Inductance and the AC resistance is specified.
Transmission Line Phase Conductor Geometry. (X,Y,Z)	Determines the TX Line self-impedance and coupling to other conductors	Power Authority	Only height is required in the GCA model
Transmission Line Tower to Remote Earth Resistance (Profile through the corridor)	Effects the ratio of EW to ground return fault current	Power Authority	These are specified tower by tower in the GCA model
Transmission Line Tower Separation (Profile through the corridor)	Combined Multi-Transmission Line model	Overlay the two systems on a map	These are specified tower by tower in the Model
Transmission Line Fault Level (Profile along the corridor)	The fault currents are the driver of LFI in the MTL model	Power Authority	In some software packages the power system and the shared pipeline can be modelled in one environment (Shared corridor) However the GCA mo0del; requires the fault currents to be input.

GCA has sourced much of the required data or where it has not been available have conducted measurements or used estimated values. Earth resistivity measurements were made in several locations, but reliable results proved difficult to obtain due to the top layer of soil being very dry. Earth resistivity is normally measured using the 4 Point Wenner method as described in Figure 22. In this method a signal generator injects a low frequency AC current into the ground and the voltage difference across a predetermined difference is measured. It is essentially a 4 wire resistance measurement. The resistance is calculated from the ratio of the measure voltage to the current and can be converted to a soil resistivity using formula. The distances apart and the depth of the probes also need to be used in this formula as shown in Figure 23.

The formula can be derived using simple geometry based on the assumption that the earth has homogenous resistivity and that the equipotential surfaces are hemispherical in shape. Because of the very dry surface conditions at the time of the measurements GCA needed to use a 4-electrode soil box with added moisture to simulate what would be expected for the sub-surface conditions. In some instances estimates were simply applied.

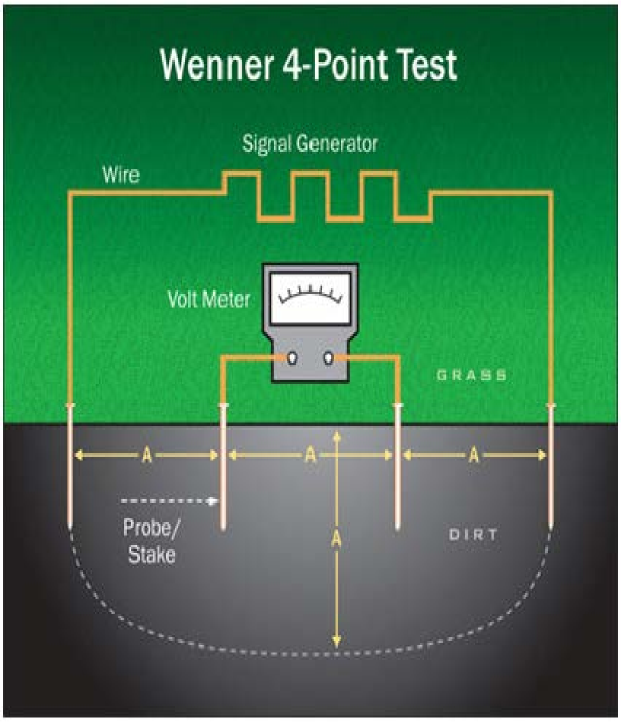

Figure 22: Resistivity Test Wenner 4-Point Earth

Soil Resistivity
4-Point Data Interpretation

$\rho = 1.915\ A\ R$
$\rho = 1.915\ (40)\ (4.5)$

$$\rho = \frac{4\pi AR}{1 + \dfrac{2A}{\sqrt{(A^2 + 4B^2)}} - \sqrt{(A^2 + B^2)}}$$

ρ = Resistivity A = Spacing of Probes
B = Depth of Probes R = Resistance (reading from meter)

If A>20B, then $\rho = 2\pi AR$ **= 1.915 *AR***

Figure 23: Calculation method for Wenner 4-Point test

7 Review of the Study Methodology and Software Tools

The modelling tool as previously mentioned was the AC Predictive and Mitigation Software developed under the auspices of the Pipelines Research Council International and distributed by Technical Toolboxes Inc, USA. This software is quite widely used by the Pipeline Industry. We have not tested this software; however based on Desk-Top review it appears to have the following capabilities:

- Allows the input of segmented shared corridor Transmission Line and Pipeline alignment data
- Each segment can have assigned: a Length, Transmission line to Pipeline separation, angular alignment, Earth Resistivity, Pipe Line Earth to ground resistance
- The overall model can be assigned an average Transmission Line Tower Separation, Tower to Remote Earth Resistance
- The nominated faulted tower can be assigned a left and right fault current. This takes into account mesh feeders where fault current flows inwards from the two ends. The fault currents cannot be calculated using this software and therefore a separate load flow program is required
- The impedance of the aerial earth wires is modelled to allow accurate determination of the split between earth return current during a fault. This allows more accurate LFI calculations.

The software appears to be quite user friendly and clearly has many in built functions. For example it is our understanding that the important electrical parameters for standard sized pipelines are built into the software which simplifies the data gathering exercise.

The study methodology has been to use substation fault levels provided by PWC and assume that the fault is always at the model boundary. In some case this has coincided with a network substation in which case the reported fault current at this point has been used. Therefore only Left or Right fault currents are entered into the model. It is possible for this software to model faults at intermediate points, but this then would rely on the fault levels and the Left/Right split being provided at intermediate points. This could be provided by the Power Authority based on a system load flow study for a number of fault locations. Because the LFI profile is a complex function of all the system variable s and the fault level and position, quite different results are possible for various scenarios. The outcome is not always intuitive and it is difficult to predict the worst case.

For example in this study the Katherine Lateral has been modelled with a fault at a distance of 5.5km from the Katherine Substation on a 22kV radial distribution feeder. In this case PWC have reported the single phase to earth fault current to be 13,000A at the 22kV Substation Bus (E&P provided with 10.17kA). This is effectively determined by the 132/22kV Transformer impedance and the substation earth grid resistance. This will be significantly reduced (Could be as low as 25%) for a fault 5.5km down the distribution line. Clearly this will reduce the LFI in the pipeline by a similar amount. Therefore using the 13,000A fault current is a very conservative approach. Nevertheless faults closer to the substation will yield increasing fault current and higher LFI on a km basis. However the exposure length is also becoming less and therefore the increasing LFI is counter balanced. A number of fault location scenarios would need to be simulated to determine the worst case. In this study this has not been done, but it must be understood that to achieve this more comprehensive analysis fault data sets must be available from the Power Authority.

If the true worst case was determined it is believed that the LFI levels for the Katherine Lateral would be significantly less than what has been presented. Nevertheless the levels could still be too high in terms of maximum touch potential once a Risk Assessment is conducted. One factor which makes this case more onerous is that the earth fault protection operating time is understood to be in the region 1 sec to 1.5 sec in the case of a Breaker Fail Back-up scenario. The long touch potential exposure time especially on a distribution line will result in lower LFI voltage limits when a Quantitative Risk analysis is conducted. Having said this rigorous Risk Analysis may consider that it is overly onerous to use the protection back-up time in terms of the probability of simultaneous events.

Having said this GCA have taken the approach of applying a very conservative analysis using excessive fault current levels and determining there is a touch potential safety issue to be addressed at the CP test locations, however no formal Risk Assessment has been conducted. In addition to this the distribution feeder has been assumed to have no aerial earth return conductors. Whilst again, this results in a worst case outcome, it is our belief that there may be one earth wire on this feeder.

The preferred mitigation strategy is to deploy new CP Test Points with equipotential subsurface Grading rings. These rings are connected to the pipeline via isolators which breakdown when AC voltages exceed approximately 2Volts which keeps the pipeline and the surrounding grounds at the same potential thus avoiding high touch potentials. Other possible mitigation strategies would be the use of Insulating gloves or increased pipeline earthing. Clearly increased pipeline earthing would be the most expense option.

In this study the main issue is that a very conservative approach has been taken and that the LFI result is so high that there was no further value in completing a formal risk assessment. For this particular case we believe there is potential that a more rigorous LFI evaluation and a formal Risk Assessment might yield a different result.

In the case of the Darwin City Gate to Manton section the same methodology has been applied. However in this case the fault has been applied at the Manton substation and has a relatively low value of 2600A (E&P provided with 2.1kA) since it is relatively distant from the main generation centre of Channel Island. In the study it is assumed the 2600A fault current flows in one direction from Channel Island to the fault. In reality this could yield slightly higher than actual results since a small proportion of the fault current would be supplied from Pine Creek and therefore the amount originating from Channel Island would be lower. However this is only a relatively small effect.

If the study had been done with the fault applied further towards Channel Island the Transmission Line Fault level would be significantly increased. Because the main area of exposure where the pipeline and transmission line are is also close to the Darwin City Gate the likely result will be a higher LFI level.

In this respect the GCA methodology is not comprehensive in terms of considering a range of fault positions and the current levels at this point. The software is capable of modelling the faults at any position and the Left/Right current levels can be input to the model. However the required input data must come from Power Authority Load Flow studies. One input screen for the GCA software package for the Darwin City Gate to Manton section is shown in Figure 24. This shows the 2.6kA faults set to 2600A. The Right Side current is set to zero. The earth wire resistance has been set to 2.24ohms/km and the GMR t0 0.8mm. The value of 2.24ohms/km at 50Hz is realistic; however the GMR of 0.8mm is our opinion too low. The GMR affects the inductance of the earth wires. The inductance may therefore be slightly higher than reality. This will result in more current being diverted to earth which is a conservative approach.

T-Line

	D - m	H - m	R - ohms/Km	GMR - m
Shield Wire #1	-5	25	2.24	0.0008
Shield Wire #2	5	25	2.24	0.0008

	D - m	H - m	IL - A	IR - A	Total Current
Phase Wire	-5	21	2600	0	2600

	Avg Twr Sep. - m	Avg Twr Res - ohms	Faulted Twr Location
Elec. Sys Parameters	350	5	67

Arc Distance (m) 0.5

Figure 24: GCA Input Data for Fault Current, Shield Wire Details, Phase Wires

8 Sanity Check of the Study Results

In order to provide a sanity check on the results and validate the GCA software algorithm the Darwin City Gate to Manton and the Katherine Lateral were modelled using an alternative software package which Evans & Peck (E&P) use for Power Systems Analysis. This package is SimPowerSystems (SPS) which is a Mathworks-Matlab Add-on Toolbox. It is capable of modelling the Multi-Line corridor system including all the transmission line conductors and the pipeline. The pipeline is considered to be another conductor. The GCA report lists the pipeline to transmission line separations for each section. In the SPS model each tower is modelled in its correct position and pipeline sections based on the GCA model are aligned. The SPS model being a network model allows the introduction of individual tower resistances to the remote earth. The pipeline impedance is derived using an internal calculator which uses, Diameter, Wall Thickness, Steel Resistivity, Steel Permeability and GMR as follows:

- Diameter – 32.4 cm
- Wall thickness – 10 mm
- Steel Pipe Resistance – 0.021 Ω/km (DC)
- Steel Pipe Relative permeability – 200
- GMR – 15.2 cm
- Earth Resistivity – 50 Ωm.

This yields a self-impedance of magnitude of 0.54 Ω/km calculated using the SPS calculator. Whilst we do not have precise data for the pipeline material or dimensions (except for the diameter) this value is within the excepted range for pipelines.[3],[4] The pipeline insulation jacket also plays an important role in determining the voltage levels since it provides both a resistive and capacitive path to the remote earth. The effective values are dependent on the surrounding earth resistivity but for values of 50 Ωm the pipeline coating can be considered to dominate. This results in the following:

- Pipe shunt resistance to ground – 250 Ω/tower section
- Pipe shunt capacitance to ground – 7 μF/tower section.

These shunt components are lumped at each tower section. All the towers have equal separation in this model of 392m which is the average value found from Google Earth for the route.

In addition it is known from the GCA report that there is a ground array at the Darwin City Gate end of the pipeline but no ground array at Manton. The pipeline is assumed to end in an insulated joint. GCA has estimated the grounding resistance at Darwin City Gates to be 2 ohms.

The transmission line tower geometry was estimated from Google Earth Street view photographs and our knowledge of standard configurations used in the power industry. Figure 25 shows the geometry which has been used for Darwin City Gate to Manton route.

[3] A.C. CORROSION ON CATHODICALLY PROTECTED PIPELINES, Guidelines for risk assessment and mitigation measures

[4] AS/NZS 4853:2012, Electrical hazards on metallic pipelines

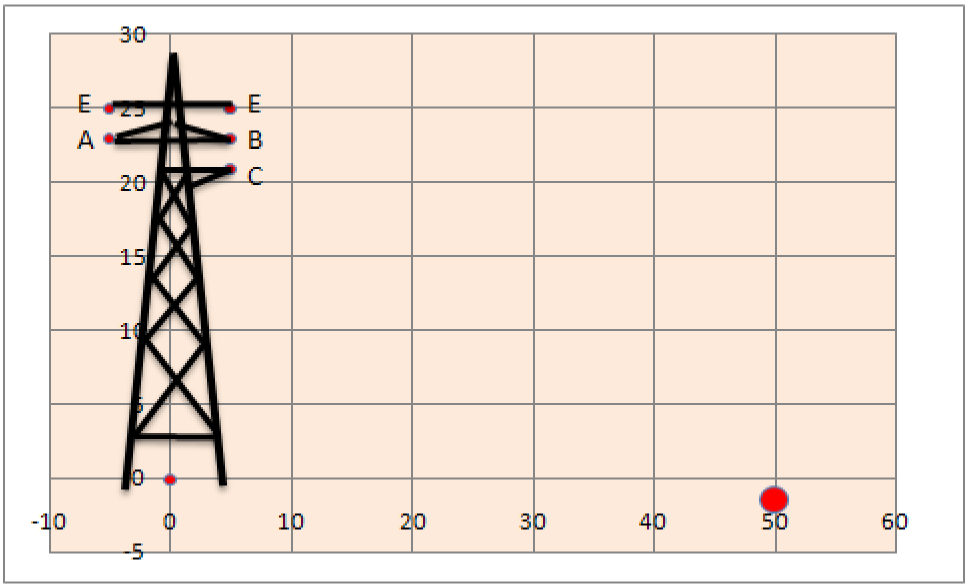

Figure 25: Transmission Line Geometry (Phase Conductors are 'Grape', EW is 'Almond')

In the SPS model the phase to ground fault level was set at 11.6kA at Channel Island based on the source impedance in accordance with the PWC data as follows:

The latest maximum 132 kV fault levels (kA) are given below:

	3 Ph. to Ground	*Line to Ground*
Channel Island 132 kV bus	*9.34*	*11.63*
Hudson Creek 132 kV bus	*7.63*	*8.86*
Manton ZSS 132 kV bus	*2.93*	*2.10*
Pine Creek 132 kV bus	*1.68*	*1.99*
Edith River 132 kV bus	*1.40*	*1.64*
Katherine 132 kV bus	*1.30*	*2.25*

With the transmission line geometry shown in Figure 25 and using 'Grape' Phase conductor's plus 'Almond' Earth Wire) the Phase to Ground fault current at Manton is 2.1kA which is consistent with the PWC result. There is a small contribution from Pine Creek to this 2.1kA. Therefore the fault current contribution sourced from Channel Island is approximately 1.9kA.

In the GCA study a value of 2.6kA has been used and it is assumed that this is totally sourced from Channel Island. This is therefore a slightly inflated value. Nevertheless in order to validate the GCA result based on the data used the fault current contribution from Channel Island was adjusted to equal 2.6kA by lowering the source impedance. In this way the results using similar input data can be compared. Figure 26 shows the pipe line voltage profile generated by the SPS model.

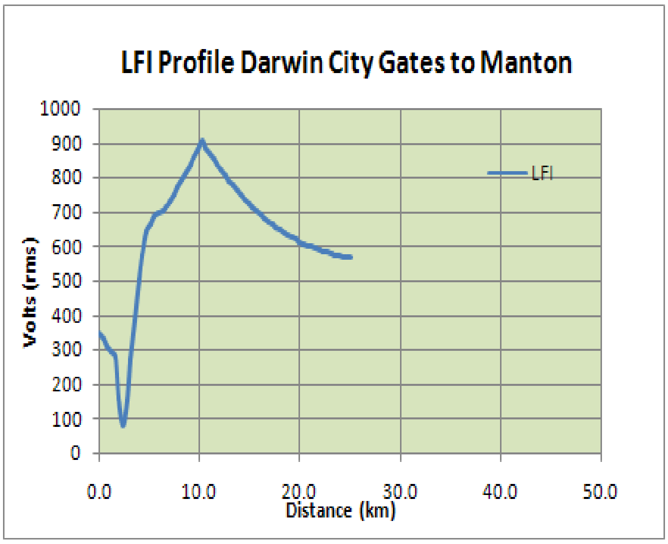

Figure 26: LFI Darwin City Gates to Manton with (Fault at Manton) (SPS Result)

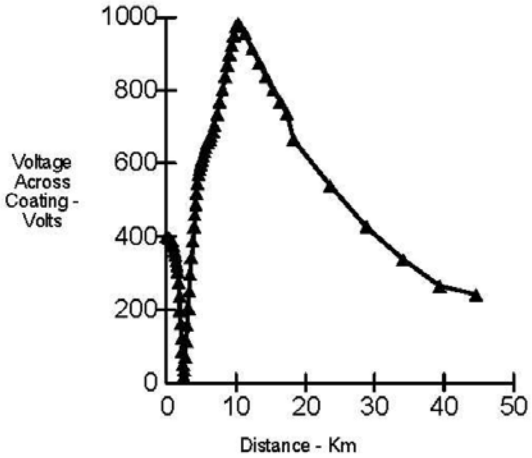

Figure 27: LFI Darwin City Gates to Manton with a Fault at Manton (GCA Result)

Figure 27 shows the pipe line voltage profile presented by GCA. The SPS and GCA results are quite similar sharing almost the same general shape. The SPS maximum voltage is slightly lower than the GCA result but given the possibility of slight differences in the model data definition especially associated with the Pipeline impedance our opinion is that there has been reasonable verification of the result and therefore the background calculation algorithms.

The SPS being a full Network model has the flexibility of being able to move the fault to alternative locations and obtain other LFI profiles. In this way the worst case can be found. Figure 28 shows the LFI profile for a fault at a location 5.5km from the Darwin City Gate.

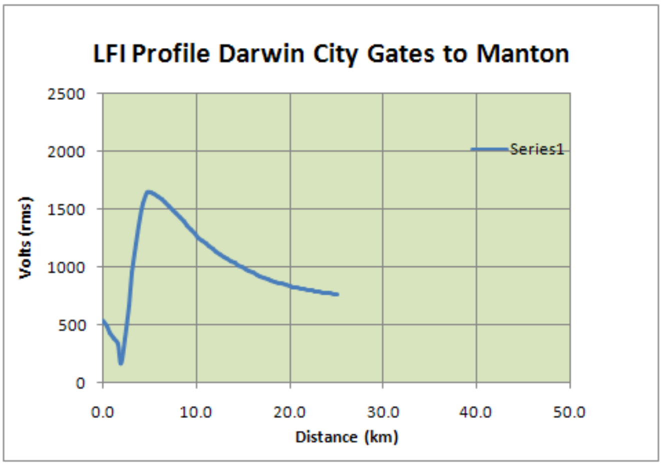

Figure 28: Darwin City Gate to Manton LFI (Fault at 5.5km from City Gate) (SPS Result)

The fault current is now 6.5kA based on the same source impedances which gave a fault level of 2.6kA at Manton. The maximum LFI voltage has now increased by nearly 80%, mainly due to the fault current increasing by 150%. The LFI increase is restricted to a lower proportion due to some of the fault current being sourced from Pine Creek via Manton.

Therefore in this instance, GCA has not considered the worst case in their analysis. Whilst GCA had already determined that the levels were too high and mitigation would be required further analysis could be argued to be unnecessary. However a rigorous treatment gives important information on maximum pipe coating electrical stress under fault conditions. Nevertheless in this case the level of 1700V would be insufficient to cause any issue.

The Katherine Lateral was also modelled in SPS using appropriate data for this 115mm diameter pipeline. In this case there is a parallel running 22kV distribution line which runs away from the Katherine Power Station and Substation. Our understanding is that this is a radial feeder and therefore does not connect to any other power sources. The phase to ground fault current can therefore be assumed to reduce with distance from the substation.

The GCA model is configured to apply a fault approximately 5.5km from the substation; however the full substation fault current has been used. In the GCA report the 22kV fault current at Katherine is stated to be 13kA. Whilst this is quite a high level (Higher than what has been given to EP from PWC of 10.17kA) it will diminish significantly in the location where the fault has been applied.

The line geometry configuration is estimated and based on the GCA model. We know that this is a simplification based on later data provide by PWC. However for illustrative purposes it is adequate. In the initial run the source impedance was lowered and the source voltage increased to achieve a 13kA fault level at a distance of 5.5km from the substation. This is a completely artificial scenario however it matches the formulation used by GCA.

Figure 29 shows the result which was obtained with the GCA result also being plotted on the same scale. The SPS and GCA results are very similar which validates the later calculations based on similar input data. The maximum LFI voltage level which is slightly greater than 2500V is very high and GCA have dismissed any further analysis or Risk assessment and have concluded that mitigation at assessable points will be required. For the Katherine Lateral this will be all the CP test points and the Katherine take off site on the main APA pipeline.

However in this analysis the fault level is expected to be much higher than reality. To test this view a fault was applied in the same location but with normal source impedances. The result was a phase to ground fault current of 2.2kA at the 5.5km point. The LFI voltage profile is correspondingly lower being a maximum value of just over 450V. This is dramatically lower and on this basis we would question the validity of moving directly to the Mitigation process without conducting a more rigorous study and based on this a Quantitative Risk Analysis.

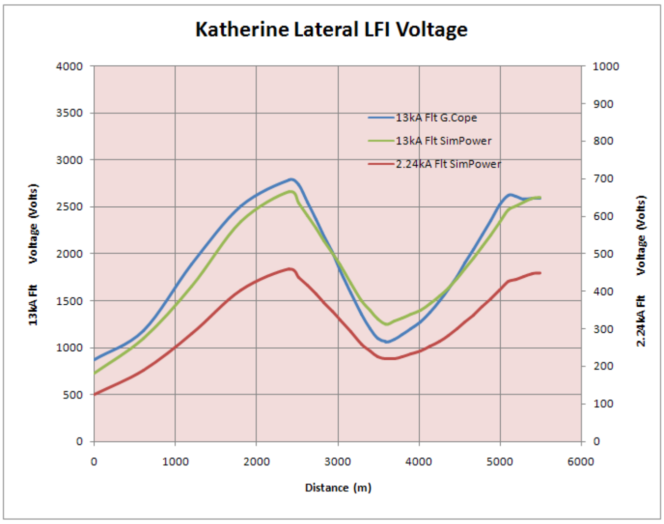

Figure 29: Katherine Lateral LFI Voltage Profiles (note secondary scale for 2.2kA fault)

The simulation modelling which has been done by E&P whilst validating the GCA calculation is not comprehensive or necessarily accurate in terms of the fault levels. Much of the data in this respect is based on our estimates and the original GCA model. Nevertheless it illustrates the point that a further more detailed study may be warranted. The outcome will very much rest on the Quantitative Risk Analysis which in our view should be carried out in this case. One of the important inputs to this will be the Distribution Fault Clearing time which is a function of the protection system. If it is decided to use the Circuit Breaker Back-up time which is in the range of 1sec to 1.5sec then the levels may still be too high. However if the primary clearing time is used then the system could prove to be satisfactory when the Risk is correctly assessed. Therefore in this case we believe it is important that the full process be executed no matter what the outcome.

Figure 30 shows a screen shot of the SPS model used in this work.

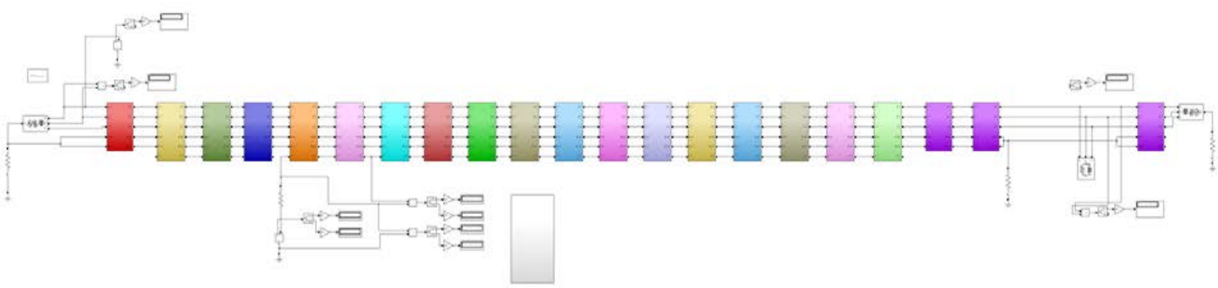

Figure 30: SimPowerSystems screen shot of the Darwin City Gate to Manton Model including the Transmission line from Channel Island and from Manton to Pine Creek

9 Review of the Proposed Mitigation Strategies

The GCA aim was to review the AC LFI Status of the three systems in accordance with the AS4853-2012 Standard and make recommendations on mitigation measures where the safety risk is unacceptable. The LFI levels have been quantified using software modelling. This has not been totally comprehensive in that a proper fault analysis has not been completed. Instead the allocation and positioning of faults has been done in a simplified way which both have understated and possibly overstated the levels in various locations. Where they have been understated the levels are still high and it is claimed by GCA that mitigation will be necessary in any case. The Katherine Lateral is an area where the levels have been overstated and there remains a possibility if a more thorough analysis and rigorous Risk Assessment was conducted it might be found that mitigation measures may not be required.

Having said this GCA has recommended AC mitigation at all CP Test Points near to the Darwin City Gate, Channel Island to Darwin City Gate and the Katherine Lateral. The recommended mitigation method is new CP Test Points with buried equipotential grading rings to remove the Touch Potential risk at the measurement point. As pointed out this strategy has only minimal effect in terms of lowering the overall pipeline voltage, however because the pipeline is buried there is normally no access. GCA recommends a separate Risk Assessment be conducted when the actual pipeline is exposed for maintenance and repair purposes. In this respect it is important to make the point that there should be caution exercised in using the numerical results from the GCA report since these may not be worst case in some areas. A more rigorous and comprehensive treatment of the transmission system fault levels is required.

The section from Manton South through Ban-Ban Springs to Pine Creek and then on to Helling Scrapper Station was shown to have relatively low LFI levels and no mitigation measures were recommended even though no formal Risk Analysis was conducted. We haven't simulated these areas as part of this review; however given the larger separation distance it seems reasonable to expect that the GCA conclusion is correct. A further fact that supports this is that for a Transmission System the fault clearing times are lower than Distribution Systems and also the probability of a fault is lower. Based on this GCA have concluded that the calculated voltage levels are satisfactory, although there has not been a formal analysis conducted.

Other locations where there is access to the Pipeline already have satisfactory mitigation in place. This includes restricted access, Earth Mats, and/or 100mm of Gravel. GCA has conducted Risk Analysis in the Katherine Lateral Take-Off point which showed the Risk to be satisfactory; however they made the comment that not all the input data could be validated.

The GCA report recommended mitigation strategy is to deploy equipotential grading rings at the CP test points in areas where the modelling has indicated high LFI voltage levels. Figure 31 shows a typical installation. It consists of a buried mat which is connected to the pipeline under fault conditions. The area on the soils surface directly above the mat is tied to the pipe potential and therefore personnel working on CP test points are never exposed to the pipeline potential relative to the remote earth. The units suggested by GCA are a different design; however the principle is the same.

The mat is not directly bonded to the pipeline rather it is connected via a voltage breakdown device. These devices conduct once the voltage exceed a low threshold. The normal DC Voltages impressed by the Catholic Protection systems are generally less than 2 Volts. If the breakdown voltage is selected to be slightly greater than 2Volts then the DC current to ground is effectively blocked. Therefore the Cathodic Protection System operation is not loaded by the earth path. Under Transmission Line Fault Conditions the AC voltage levels are much higher and therefore the devices conduct and effectively connect the mat to the pipeline. The basic premise of these surge diverters is to provide a low impedance path for low AC voltages and a high impedance path to low DC voltages effectively decoupling the pipeline earthing systems.

The device is required to withstand significant circulating current during the fault condition. When under steady state conditions the devices will conduct, if the voltage level is sufficiently high (>2V). Figure 32 shows a typical voltage breakdown device. This device is capable of carrying 3700A for 0.5 seconds. GCA has indicated a rating of at least 500A would be required. We would caution that this value is based on only one fault scenario on each study section and therefore may not be the worst case.

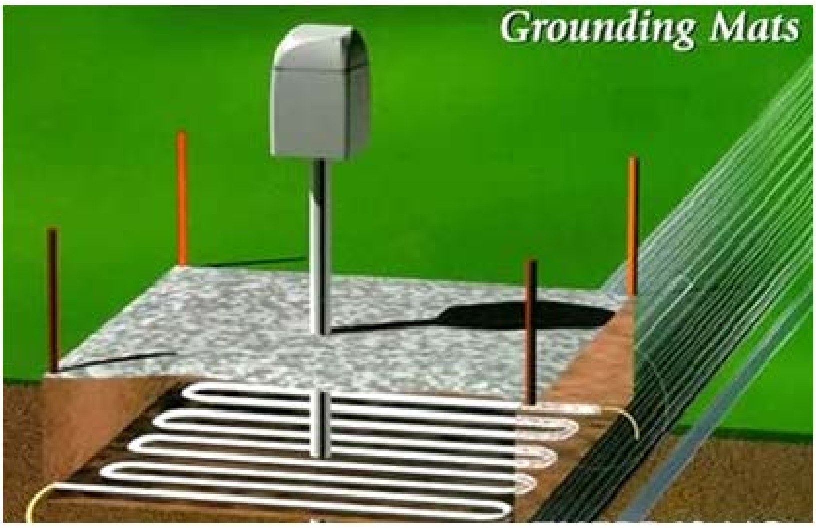

Figure 31: Pipeline CP Point Equipotential earth mat

Figure 32: Voltage break over device

There is evidence that mitigation of LFI touch voltages will be relatively high in some sections of the study areas. In the case of new CP point installations the only sensible solution is to install equipotential earthing mats or grading rings. This should be combined with the voltage break over devices. For existing CP sites if a Risk Assessment is conducted consideration would need to be given to mitigations measures other than Grading Rings. The Standard has the following comments:

> *If the touch voltage in the exposure zone is exceeded, mitigation should be by one or more of the following:*
>
> *a) Gloves*
>
> *b) Asphalt*
>
> *c) Earth grid with gas discharge tube. For personnel protection, the gas discharge tube firing voltage should typically be 20 V.*

Therefore whilst option (c) has been recommended we believe it is also justified to give consideration to option (a) which may be a lower cost solution. There are many factors which must be considered when making the best choice, however this analysis does not appear to have been done.

10 Steady State Voltages and AC Corrosion

The steady state voltages at a number of CP test points were measured by GCA. These were found, in the worst case, to be in the range of 2 to 4V. These points were logged over a 20hr period so as to capture a range of transmission line loading. Typically the levels vary throughout the day in response to load changes. Because the three phases are not geometrically balanced relative to the pipeline the magnetic field does not completely cancel and hence there is a resultant component which links the pipeline. As well as geometrical unbalance there is also phase current unbalance, Phase current unbalance is a more serious issue in distribution lines, increasing as the working voltage reduces. The GCA report indicates that the measured voltages are below the threshold at which AC corrosion is thought to manifest. At this point the recommended strategy is regular monitoring of the AC voltages at the CP test points. If then in the future the voltages become too high the available mitigation strategies are as follows:

- Increasing the distance between pipeline and high voltage line
- Optimum arrangement of phases and earth wires (Transpositions)
- Earthing of pipeline
- Compensation of induced voltage
- Installation of isolating joints
- Repair of coating defects
- Exchange of soil in the vicinity of pipeline
- Use of parallel earthing cables.

All of these are expensive solutions to implement and therefore the GCA recommendation is regular inspections in the future to establish if AC corrosion is having any material effect on the pipeline. They point out that historical inspections have not shown an AC corrosion problem. Nevertheless it has proved to be a significant issue in other systems worldwide.

The unbalances inherent in the transmission line coupling to the pipeline can often be significantly reduced by designing the power lines with regular transpositions. Accurate modelling is however required to quantify the benefit of transpositions. With transpositions the geometric position of the phases is rotated at regular intervals through the shared corridor which causes a reduction in LFI voltage due to cancellation effects.[5]

[5] A.C. CORROSION ON CATHODICALLY PROTECTED PIPELINES, Guidelines for risk assessment and mitigation measures, CEOCOR

11 Implementation of GCA Report Recommendations

It is clear that APA has accepted the major findings and is prepared to implement the major physical recommendations of the GCA report. However mentioned often within the GCA report is the requirement under the standard to perform a formal risk assessment. This critical part of the recommendations does not appear to have been actioned.

While the use of grading rings at measurement sites is recommended for local protection it must be remembered that this will have little mitigation effect on the touch potentials due to LFI along the pipeline. An overall electrical safety strategy based on the risk assessment is required.

With regard to the implementation of the work, the methodology seems reasonable and robust assuming the excavator is sized according to the rate of work required to be performed and moving between sites is executed efficiently. In particular a rate of two grading ring installations per day on the AGP & Katherine lateral needs to be maintained. Additionally it is assumed that as part of the installation process at each site, time has been allocated for a final inspection and test with a certificate of test completed for each installation.

In general the bill of materials also seems reasonable to complete the work schedule indicated in the *Special Projects Items for Approval AC Mitigation* document. The scope of works shows 28 standard test points and 9 ERP test points a total of 37 installations. This indicates an allowance of 15m of zinc ribbon and 14m of cable for each grading ring. Although E&P have not viewed the grading ring design this allowance appears appropriate. E&P assumes the cable size has been calculated to carry the induced pipeline current under power line fault conditions. Early notification of the commitment to proceed should be given to ensure materials are ordered and arrive before planned commencement of activities.

E&P assumes that APA has sourced the correctly rated earth decoupling devices as mentioned in the GCA report and that the effect of any capacitance in these devices on pipeline operations has been considered. The actual component manufacturer and model number has not been provided for consideration by E&P as part of this report.

Although two days has been allocated for each test point installation along the t Channel Island Spur an area of concern is that the traffic management plan for the work has not yet been developed and may impact the work efficiency of the team. Project constraints need to be controlled rigorously by the project manager with a small end of week report (email) detailing actual progress against planned progress to ensure there are no unforseen outcomes.

PWC should bear in mind that the plan states no contingency has been made for the listed contingent events stated in the *Special Projects Items for Approval AC Mitigation* document. PWC prefers to work this way with any additional costs due to contingent events addressed as they occur. With this approach to project delivery APA must ensure good reporting and PWC must allow for an appropriate contingency fund.

12 Conclusions and Recommendations

Based on our review of the GCA report we make the following comments and 0bservations:

12.1 The modelling software used by GCA appears to give valid results. E&P have verified that similar results can be achieved using a completely different software package using similar input data.

12.2 The model definition and input data has been quite detailed in terms of separation distances/angles, transmission line towers. However whilst the software has the capability to model faults at any point along the transmission line, this feature has not been exploited in this study. Therefore we believe there is likely to be some limitation in the study in terms of exposing the worst case and conversely a user of the report could overestimate the LFI voltage at specific locations along the length of the pipeline.

12.3 Whilst the software used by GCA has the capability to model the effects of power system faults at any location along the pipeline it is necessary to input the transmission line left and right fault currents at the point of the fault. These faults typically occur at towers. Because the software does not have the capability to input all the power system network parameters the line impedances and fault currents being contributed from the various network sources cannot be determined. That is the software does not have full power systems load flow capability. Due to this there is a reliance on input data from an external power systems load flow analysis which is typically provided by the operator of the transmission line.

12.4 Because a comprehensive analysis of the effects of faults at many locations along the service corridor has not been conducted it is likely in some instances the worst case pipeline voltage rise has not been determined. For this reason it is recommended that the results from this study should not be used for other than the intended purpose. For example the maximum pipeline coating voltage stress is likely to be higher in some areas than what has been stated in the GCA report.

12.5 The Katherine Lateral which was analysed by GCA, has been checked using alternative software with similar input data. In this case similar results are obtained which again validates the software algorithms. However the Fault level used by GCA is unrealistically high. The fault level of 13kA (E&P was provided with a value of 10.17 kA) existent at the Katherine Substation has been applied 5.5km down the distribution line where the pipeline exposure is maximum. The result is very high LFI voltage levels. In this case we would recommend repeating the study using the correct fault current based on a load flow result. Once a rigorous Risk Analysis has been completed it is very possible the outcome for this section of pipeline will be quite different.

12.6 In all the items studied except for the Katherine Take-Off point there has been no formal risk analysis. Whilst in the majority of cases the outcome is likely to be the same this is not in alignment with the methodology outlined in Australian Standard AS4853:2012 or the conclusion in section 7.1 of the GCA report.

12.7 GCA makes no comment on the issue of Earth Potential Rise (EPR) due to a phase to ground fault at a tower in close proximity to the pipeline. The effect of electric stress levels on the pipeline insulation and the issue of step potential near the pipe when EPR & LFI potentials combine should be addressed in APA's analysis of the pipeline risks.

12.8 When conditions are optimum a soil resistivity profile of areas of interest along the pipeline should be performed. To negate the issue of poor surface conditions longer rod electrodes should be used while acquiring the measurements. This data would then be available to more accurately calculate LFI potentials and the effects of voltage stress on pipeline insulation. It is likely a large range of values will be measured along the pipeline negating the need to use average values at each tower in the modelling.

12.9 Although this report has not specifically addressed the issue of removing the depleted anode bed it is indicated in APA's *Special Projects for Approval AC Mitigation* document that removing the depleted anode ground beds is a license/AS2885 requirement. However, AS2885.3 Operation & maintenance 10.6.5 Section (d) only states in the case of a pipeline abandonment that the anode bed can be disconnected 600mm below ground. GCA's report Addendum 3 states there is only minor influence on the LFI study from the depleted anode bed and only mentions AC and direct voltage measurement during disconnection (decommissioning). Removal of the bed may have an environmental or statutory reason.

12.10 E&P recommend that APA be approached to check the requirement to remove the depleted anode bed in their license. If the license does not specifically call for the removal of the depleted anode bed then possibly only disconnection is required.

12.11 The GCA report section 7.3 recommends that where it is difficult to install grading rings or pads that an alternate approach which includes the use of specific PPE may be adequate. The use of specific PPE and procedures at certain test sites while perfoming routine testing should be discouraged. When perfoming electrical testing on any pipeline the use of insulating gloves, electrical footwear and appropriate procedures should be standardised.

The key mitigation strategy presented is the use of Subsurface Grading Rings to maintain a local equipotential working area at CP test points. For areas where the LFI is found to exceed the limits set on a Risk Basis and where new CP equipment is being installed this is inarguably the best approach. However at old CP sites when a Risk Analysis is conducted other lower cost mitigation strategies should be critically evaluated. The use of insulating gloves is acceptable according to the Standard however the appropriateness of this strategy in the APA environment needs to be evaluated. It must be noted that the installation of grading rings will in most cases not reduce the touch potential along the pipeline other mitigation strategies will need to be explored during the risk assessment.

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