Customer assets directly connected to REFCL networks: a preliminary risk survey

An initial indicative report to Energy Safe Victoria on factors that may create potential risks when a customer site is directly connected to an electricity distribution network protected by a Rapid Earth Fault Current Limiter (REFCL).

Contents

Disclaimer

This report outlines the results of a preliminary indicative survey of particular examples of high voltage infrastructure carried out to provide broad insights into the drivers of any associated risks. It contains data, observations, analysis, estimates, findings and recommendations, all of which are preliminary and indicative in accordance with the purpose of the project. The author has used data provided by third parties which is in many instances unclear or incomplete. While care has been taken in the processing and analysis of this information, readers should recognise that it has been provided without any warranty as to its accuracy or completeness. No liability is accepted by the author for anything in this document. Readers who wish to rely on this report for any purpose beyond that reflected in the project objective should undertake their own investigations.

 Tuesday, 20 June 2017

1. The project

Hundreds of large industrial and commercial customers in Victoria take their electricity supply at high voltage, i.e. their assets are directly connected to 11kV and 22kV distribution networks. They range from public infrastructure suppliers such as electric rail and water supply to public sector agencies such as defence to private industrial and commercial plants in a wide range of industries.

From 1st May 2016, Victoria's electrical safety regulations require 45 rural distribution networks to change to REFCL protection over the next seven years. A REFCL network has a very different response to earth faults than a traditional network. This response exposes network assets to higher than normal voltage for a short period. Failure of any network asset during this period creates a cross-country fault[1] which may negate the safety and supply reliability benefits of the REFCL. A cross-country fault in high fire risk conditions may easily start a fire at the site of the original fault.

To prevent cross-country faults and preserve the targeted fire risk reduction benefits, distribution businesses are 'hardening' their networks prior to REFCL installation. Hardening requires removal or replacement of all assets known to be susceptible to higher than normal voltages. For example, distribution network owners are replacing around 40-50 per cent of surge diverters as well as a limited number of high voltage cables selected on the basis of test results.

The great majority of residential and business electricity customers are unaffected by the change. A high-voltage to low-voltage transformer between their 400/230 volt electrical equipment and the high voltage distribution network isolates them from the higher than normal voltages produced by REFCL operation. However, nearly 130 customer sites take supply at high voltage directly from networks in the REFCL rollout. Part of the electrical infrastructure in these sites is simply an 'over the fence' extension of the distribution network. These customer assets are exposed to higher than normal voltages in REFCL operation and if they remain directly connected to the network, to avoid risk of cross-country faults these assets must be hardened along with network assets.

This means Victoria's powerline bushfire safety may depend in part on customer assets. Further, production continuity in some large rural industries may depend on their assets' ability to withstand higher than normal voltages.

To better understand risks associated with this issue, Energy Safe Victoria commissioned this preliminary review of customers' high voltage assets at ten[2] of the known 130 customer sites. The sites were selected on the basis that they contained high voltage infrastructure representative of the full cohort, i.e. old and new, simple and complex, extensive and limited, etc. Customer assets at the selected sites have been reviewed to assess the drivers of associated potential risks.

The review included both desktop analysis of asset data supplied by customers and distribution network businesses, plus site visits to inspect the assets, gather further information and discuss the risks with the customers' electrical asset management teams.

The stated goal of the review was to 'Provide an initial indicative report to ESV on factors that may create potential safety risks when HV customer sites are supplied by REFCL-protected networks.' Other (non-safety) risks have also been recognised in the review and briefly included in this report.

[1] The second fault caused by the asset failure is termed a cross-country fault because it is often remote from the first fault. The REFCL cannot simultaneously keep the current in both faults low enough to prevent fires.
[2] During the course of the project, customer assets on two additional sites were added to the sample (both were desktop reviewed, one was visited and one reviewed on the basis of customer-supplied photographs) making a total of twelve sites covered by the asset survey.

2. Findings

This review of customer assets indicates that, recognising the small size of the sample:

1. The primary bushfire ignition risk is a cross-country fault should a customer asset fail to withstand higher than normal voltages during REFCL response to an earth fault elsewhere on the network.
2. The consequences of a cross-country fault can include:
    a. In high fire risk conditions, a fire at the site of the original fault. However, this is unlikely if either the original fault is not of a type that would normally cause a fire, or it is not a sustained fault.
    b. Customer asset damage with
        i. Potential risk of interruption to normal site activity, lost production and potential loss of stock due to loss of supply.
        ii. Potential risk of injury or death of anyone exposed to the failed asset at the time.
    c. Network asset damage and consequential loss of supply to other customers.
3. Cross-country faults have proven to be rare in the only REFCL network operating in Victoria over the past five years (perhaps one per cent of all earth faults).
4. Risk from customer assets represents a small increment (perhaps three per cent) of Victoria's total risk from cross-country faults.
5. Safety risk from customer assets is of the same nature and likely no greater 'per asset' than that arising from the same assets deployed in distribution networks.
6. Risks from customer assets may in many cases be cost-efficiently mitigated without isolation transformers between the customer site and the distribution network.
7. Customers and network owners have a common interest in prevention of asset failures. Mitigation costs may be reduced by early technical information sharing and collaboration.
8. Clarity about the boundary between customer assets and network assets would strengthen accountability for safety risks.

3. Recommendations

The following actions would reduce risks arising from customer assets directly connected[3] to REFCL-protected networks and would also reduce risk mitigation costs. Many of these actions would most appropriately be undertaken by distribution businesses:

1. **Educate and work with customers:** Network owners should engage and communicate with customers at an on-site technical level, not just at a corporate level. Network technical experts should visit customer sites and brief electrical maintenance teams on the rationale for the REFCL roll-out, the technical implications for their assets and business operations, and explore with them possible cost-effective approaches to risk mitigation.
2. **Encourage and support customers to carry out tests to clarify risks:** Two specific sets of tests are recommended:
    a. Partial Discharge (PD) tests of high voltage cables on customer sites. Depending on the test results, arrange for remedial action on vulnerable cables. The PD test method and acceptance criteria should match the REFCL operating practices[4] of the

[3] Network owners may choose to isolate customers from REFCL effects by using special isolation transformers (see Section 9 below), in which case many of these recommendations would not apply.
[4] Especially the level and duration of voltage displacement by the REFCL following an earth fault.

   network that supplies the site. None of the customers reviewed are currently doing PD tests on any assets.
   b. Dissolved Gas analysis (DGA) tests of customer transformers where this is not already in place. Depending on test results, bring forward replacement or refurbishment of transformers that show indications of seriously deteriorated insulation. Many customers are already doing this though the extent varies.
3. **Inhibit further growth in risk:** Provide customers with technical specifications for REFCL-compatible surge diverters, voltage and current transformers, cables and power transformers. Encourage them to use these in their current and future asset purchases.
4. **Assess operations procedural options:** Work with customers to explore the viability of operational procedures to disconnect non-essential high voltage infrastructure during periods of high fire risk as an alternative to upgrading these assets.
5. **Negotiate complex sites:** In a small minority of sites, the issues may be very complex. The best outcome is most likely to be achieved if the distribution business and the customer collaborate to jointly identify and assess technical options to find the most cost-effective solution as a basis of a negotiated agreement on mitigation investment.
6. **Clarify residual uncertainties:** Investigate (by test if necessary) two specific potential risks where some uncertainty remains due to limited information:
   a. Performance of typical VTs under REFCL operation conditions.
   b. The over-voltage withstand capability of neon voltage indicators and associated high voltage capacitive taps in 22kV metal-clad switchgear.
7. **Clarify the asset ownership boundary:** Network owners and customers should liaise to identify the ownership of assets at or close to the site/network boundary, in particular metering transformers, supply cables and surge diverters.
8. **Include directly connected customer assets in REFCL commissioning tests:** The over-voltage soak tests carried out during REFCL commissioning must include directly connected customer assets if these tests are to provide assurance of bushfire risk reduction benefits.

The assets selected for review in this project may not include either the simplest or the most challenging customer-owned high voltage infrastructure among the 130 customer sites affected by the REFCL rollout. However, the above recommendations are considered to provide a reliable starting point for a strategy covering the great majority of affected customer assets.

4. The risk profile of a REFCL-protected network

REFCL-protected networks have a different risk profile to traditional networks. The difference is apparent in the network's response to an earth fault, i.e. failure of an asset to maintain electrical isolation from earth.

Traditional networks experience stress from high currents in earth fault events

In traditional networks, earth faults cause very high currents to flow on the faulted phase, stressing all network assets along the current flow path between the zone substation and the fault location. Consequential asset failures caused by this stress can occur anywhere along this path. Consequential failure modes include conductor joint failures, earth grid failures and movement of conductors and transformer windings due to magnetic forces. If the fault is caused by asset failure, the high current flow often severely damages the failed asset. In REFCL-protected networks, earth faults produce very low fault currents[5] and these failure modes are absent and asset damage is minimal.

REFCL networks experience stress from high voltages in earth fault events

In a REFCL-protected network when an earth fault occurs, the REFCL displaces the neutral voltage of the whole network to quickly reduce the voltage on the faulted phase to near-zero. This greatly decreases current flow and damage at the site of the fault. It also increases the voltage on the two un-faulted phases, placing over-voltage stress on all assets connected to these phases. If assets are vulnerable to higher than normal voltage levels because of inadequate ratings, age or other forms of deterioration, this stress can trigger a consequential failure of asset insulation, resulting in a second earth fault. This creates what is termed a cross-country fault as the second fault can occur anywhere on the network, often a long way away from the original fault.

Even if asset insulation does not break down immediately, the higher than normal voltage caused by REFCL operation can lead to heating of some assets such as voltage transformers and surge diverters which if prolonged, can also cause asset failure and a second earth fault. Partial discharge can also be triggered during the period of over-voltage, leading to slow cumulative deterioration of insulation over time and increased risk of a future failure.

A cross-country fault can result from asset failures on the distribution network or within customer premises – the effect is the same, regardless of location or ownership.

Theoretically, a cross-country fault could also be due to pure coincidence – a second network fault on a different phase of the network caused by an event which is independent and unrelated to that which caused the first fault, e.g. car into pole, tree fall, etc. The odds of this happening will depend on ambient conditions (storm, high winds, etc.) and the duration of the REFCL voltage displacement. These odds are likely to be vanishingly small with the short durations proposed to date for Victoria's REFCL networks.

The main potential risk in REFCL networks arises from cross-country faults

A single earth fault in a REFCL network is a lower risk event than in traditional networks. Risks arise if a second fault occurs while the first fault is present, i.e. a cross-country fault.

A cross country fault can cause energy release at two different locations:

- At the site of the original fault. This can lead to increased asset damage (and possible supply interruptions to other customers) or if the original fault is a wire down or a tree touching a line, etc., it can lead to a fire.
- At the site of the consequential fault. This can cause asset damage, interruption to supply and customer operations.

Cross-country faults can negate the risk reduction benefits of REFCL operation. Victoria's powerline bushfire safety research program has proven that REFCL response to an earth fault quickly reduces fault current to such a low level that there is a greatly reduced risk of fires occurring even in extreme conditions. A REFCL also greatly reduces the risk of asset damage by limiting energy release in the

[5] This is only true for the 'high fire risk' mode of REFCL operation. On non-fire risk days, if a sustained earth fault occurs, the network will revert to Neutral Earth Resistor (NER) protection which will produce the high fault currents typical of a non-REFCL network.

fault. However, when a cross-country fault occurs and provided the original fault is still there, high fault currents may flow in both fault locations – the original fault and the consequential fault. A REFCL is not effective when two faults are present on two different phases of the network. If the original fault is a sustained wire down, tree-contact or similar, a cross-country fault can produce enough fault current to start a fire in high fire risk conditions.

Network hardening should include directly connected customer assets

Cross-country faults are a known risk factor in REFCL-protected networks world-wide. Networks in countries that use resonant earthing (on which REFCLs are based) are designed from the start to withstand the over-voltage levels inherent in REFCL operation. In jurisdictions that are introducing resonant earthing (including Victoria), work is carried out prior to REFCL implementation to 'harden' the network by replacing assets known to be vulnerable. For added assurance, REFCL commissioning procedures include over-voltage 'soak tests' to prove the over-voltage withstand capability of network assets.

If the targeted level of residual risk is to be achieved by these procedures, it is necessary they include customer assets, not only network assets, since 'safety risk per asset' is independent of ownership.

Local risks from customer asset failures: safety is less problematic

Local risks from the failure of a customer asset include asset damage, interruption to customer activities, lost production and threats to preservation of stock, e.g. refrigerated foodstuffs. If the customer is a supplier of public services, they may include interruptions to services such as electric trains and water supply. These risks may have a high financial cost. However, local safety risks are generally well mitigated.

Local safety risks apply to anyone in close proximity to the consequentially failed asset. They include possible injury or death from arc-flash, explosion, etc. These risks are less problematic because:

1. The great majority of customer assets reviewed were rated to withstand the higher than normal voltage levels produced by REFCL operation[6]. Assets with inadequate ratings should be replaced during network hardening works for REFCL commissioning.
2. All networks are designed to safely deal with the high currents that can occur in cross-country faults. These currents are no greater than those that can occur in phase-to-earth faults and phase-to-phase faults in non-REFCL networks.
3. Under standards enforced by safety regulators such as Energy Safe Victoria, network owners and customers who own high voltage assets must design, construct, maintain and operate these assets to mitigate safety risks from faults to a level that protects the safety of employees and the general public[7].

[6] For example, cables manufactured to Australian Standard AS 1429 – this standard follows the IEC standard for European networks that operate with REFCLs. It permits 22 kV cable to be operated for up to 8 hours with full phase-to-phase voltage applied phase-to-earth. Most non-cable assets reviewed were rated to withstand 50kV for one minute which is adequate for REFCL networks.

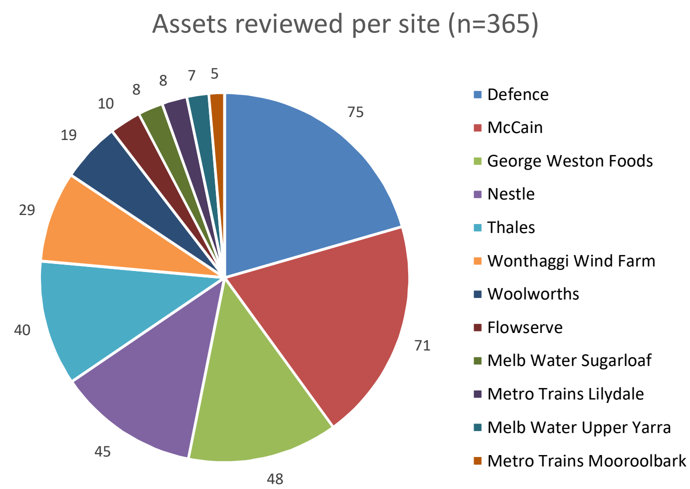
[7] It is possible that some older infrastructure may have been designed and built to a lower standard than now applies. In such cases, local safety risks may be higher, independent of whether the supply network is protected by a REFCL or not. The major of reviewed infrastructure was built to current standards.

The primary safety risk reviewed in this project is the risk of a fire at the site of the original earth fault rather than local effects near the consequential failure of a customer asset.

5. Customer assets reviewed

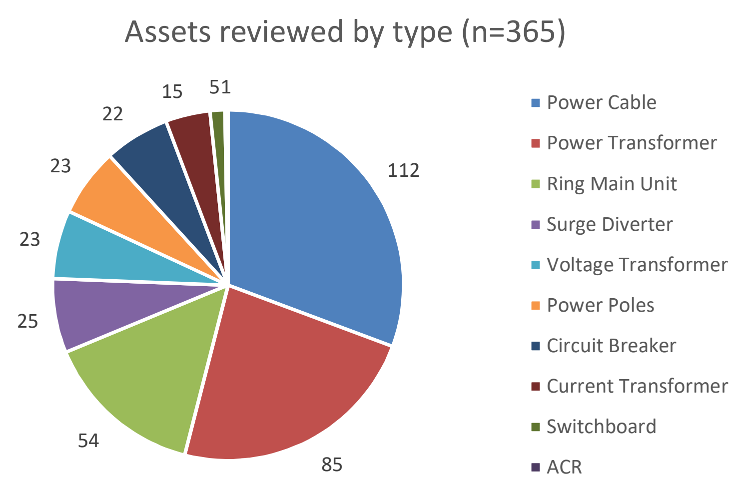
In total, 365 customer-owned high voltage assets were reviewed[8]. The review covered a wide range of sites, from some with very extensive high voltage infrastructure to some that were quite small, as shown in Figure 1.

Figure 1: Customer assets per site



The number of each asset type reviewed is shown in Figure 2. The most common customer assets were power cables, power transformers and ring main units (a common type of high voltage metal clad SF_6 switchgear) which together made up more than two thirds of all assets reviewed. The remainder comprised a diversity of seven different types of high voltage assets.

Figure 2: Customer assets by type



[8] The review also covered 54 assets that were determined in site visits to be owned by the distributor or not relevant to the review, e.g. not in service unless the site is separated from the supply network.

Typical examples of the three most common asset types reviewed are shown in Figure 3.

Figure 3: Most frequently encountered high voltage customer asset types

Power cables **Power transformer** **Ring Main Unit**

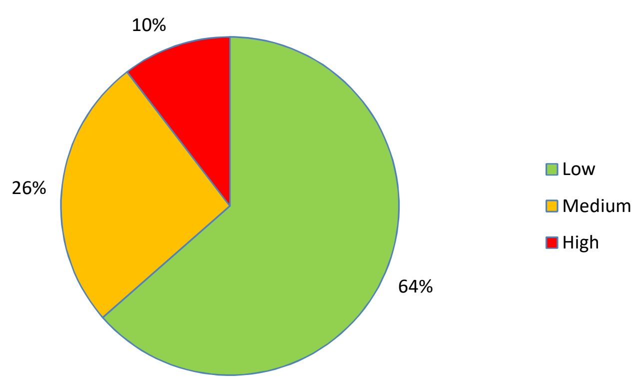
An estimate of the risk of possible asset failure under higher than normal voltage produced by REFCL operation[9] was developed based on several indicators: asset voltage ratings, asset age, asset test results if available, industry experience of over-voltage failure of that asset type, completeness of data to confirm adequate capability, etc.

Three levels of risk were defined:

- **Low:** No particular action should be required beyond basic inspection and inclusion in REFCL commissioning soak tests.
- **Medium:** There were no definite indicators of risk but tests (either or both DGA and PD) are advisable to guide a decision on whether action is appropriate or not.
- **High:** Action is clearly indicated, generally either to replace or refurbish the asset.

The distribution of assessed risk from customer assets under REFCL voltage displacement is shown in Figure 4. Only 10% of assets were assessed as clearly requiring replacement action, though additional replacement action may be indicated when assets in the medium risk category are tested.

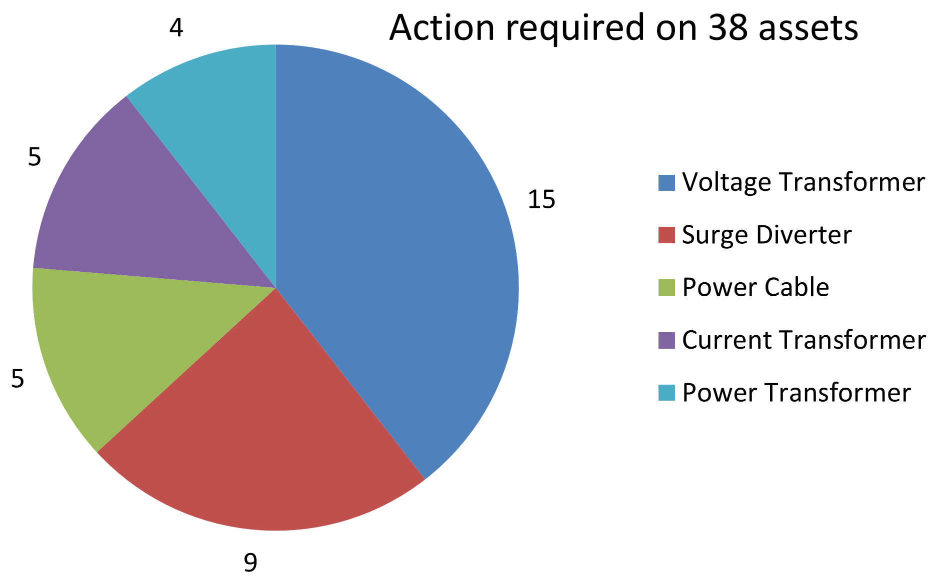
Figure 4: Estimated risk from customer assets under REFCL operation



[9] Risks from other causes were not assessed. These include a diversity of failure mechanisms that are not affected by the presence of a REFCL on the network, e.g. overload, lightning, mechanical breakdown, etc.

The assets in each category of risk are shown in Figure 5 through Figure 8.

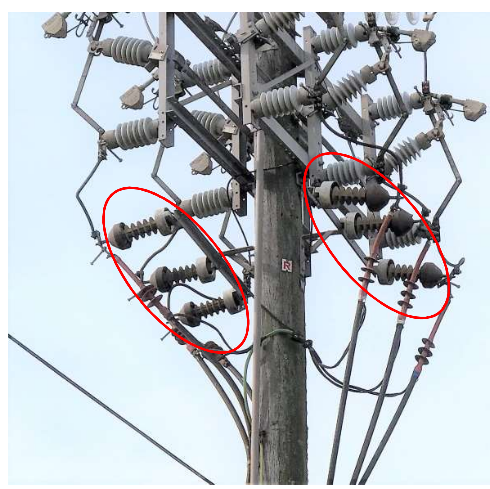
Figure 5: Customer assets estimated to have HIGH risk level under REFCL operation



The most common requirement for replacement was for voltage transformers, surge diverters and power cables. This result was dominated by the presence of low-rated (or unknown-rating) voltage and current transformers embedded inside metal-clad switchgear, as well as very old surge diverters in two specific customer sites – see Figure 6. Access to the embedded transformers to determine their ratings must in many cases await a full or partial shutdown of the customer's plant.

Figure 6: Replacement likely required: metering transformers in metal-clad switchgear, old surge diverters

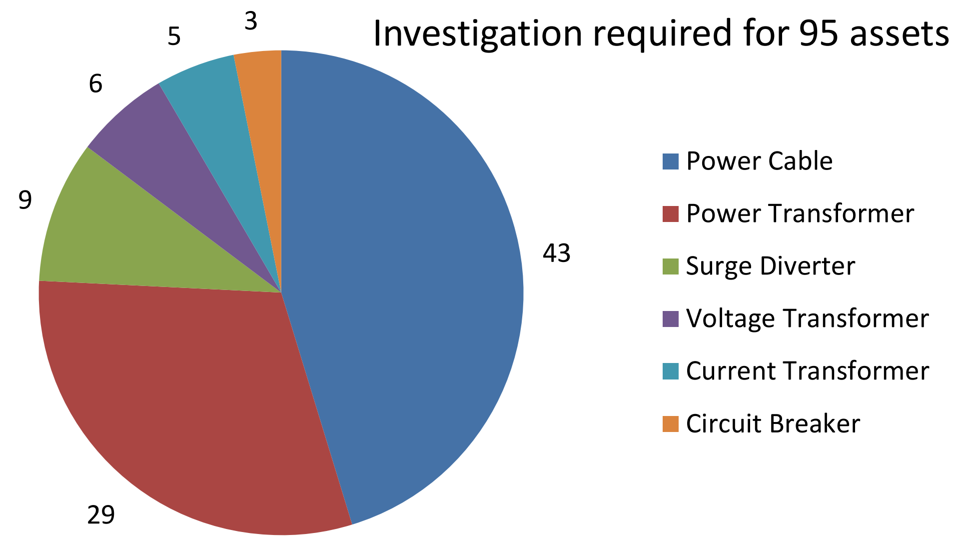
Embedded metering transformers



Old surge diverters

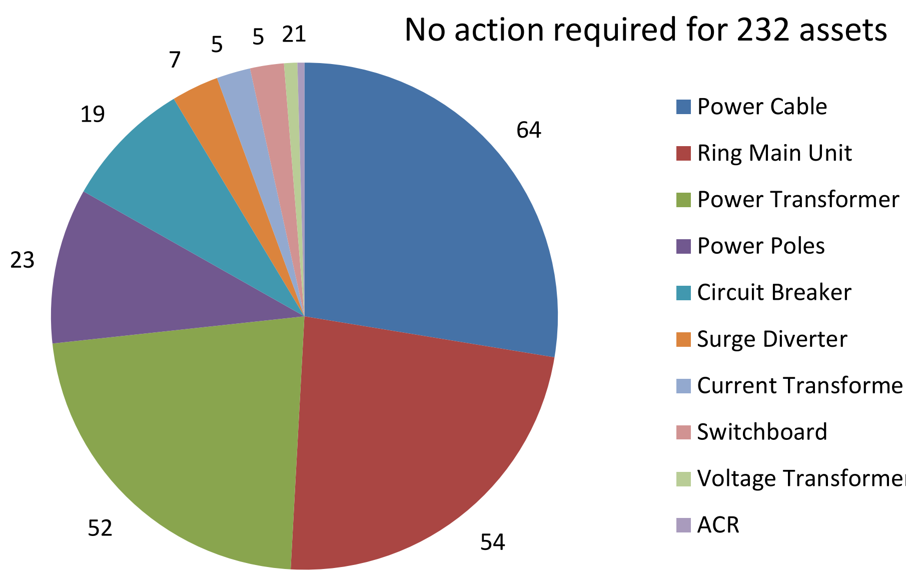
Replacement or refurbishment of four ageing power transformers is also indicated. The customers concerned were aware of this requirement and already planning early replacement unrelated to the REFCL rollout.

Figure 7: Customer assets estimated to have MEDIUM risk level under REFCL operation



The largest requirement for tests is for PD tests of high voltage cables and DGA tests of power transformers – see Figure 7.

Figure 8: Customer assets estimated to have LOW risk level under REFCL operation



For 90% of the assets reviewed, the risk of problems arising from the move to REFCL-protection appeared to be low to medium. The actions indicated to reduce it further were the same as those to harden distribution networks – replacement of incompatible and unsuitably rated assets and those where test results indicate end-of-life asset failure is approaching.

Customer automatic protection and control systems warrant consideration

Most customer automatic protection and control systems are similar to those found on distributions networks: overcurrent and earth fault, a small minority of which is directional. In sites with cogeneration, more specialised systems were found, such as negative sequence protection and neutral displacement protection. In the case of electric train supplies, 'loss of phase' protection systems to prevent excessive rectifier output ripple were also identified.

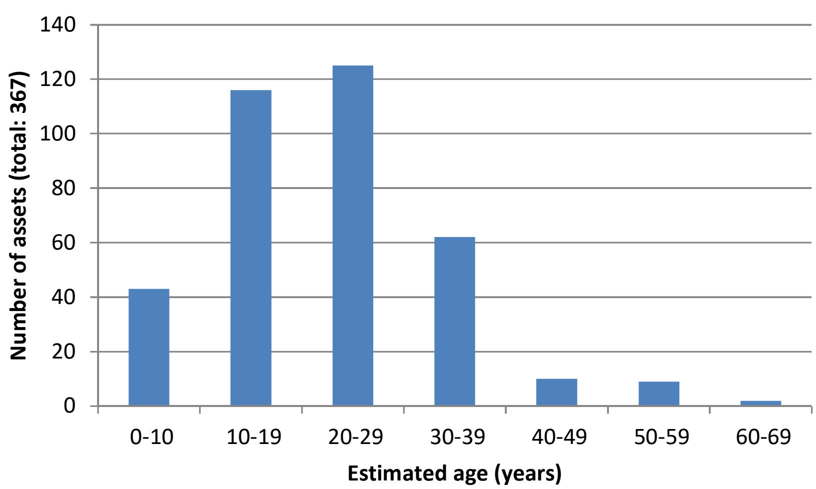
Coordination of customer protection and control systems with corresponding systems on the supply network must be considered in the REFCL rollout. However, any required action should be straight forward. Customers with assets directly connected to a REFCL-protected network will face the same challenge as the network owner - primarily, how to locate a fault when the fault current is so low it leaves little or no evidence of its occurrence.

If network owners' stated intentions for treatment of sustained faults are implemented, either a feeder trip (in fire risk conditions) or reversion to NER-protection (at all other times) will occur in seconds rather than minutes. In either scenario, customer protection systems will function as usual and coordination is not expected to be a driver of material risks or major costs.

Customer assets ages vary widely

The estimated age of the 365 customer assets reviewed is shown in Figure 9.

Figure 9: Customer assets by estimated age (as at H1 2017)



Age was precisely known in some cases or it was estimated based on discussions with maintenance teams, e.g. installed when the facility was built, etc. Estimated asset age ranged from less than one year (just purchased) up to 66 years. If a nominal service life of 40 years is assumed, then by the end of the seven year REFCL rollout, the majority of the reviewed assets will be well into the second half of their service life.

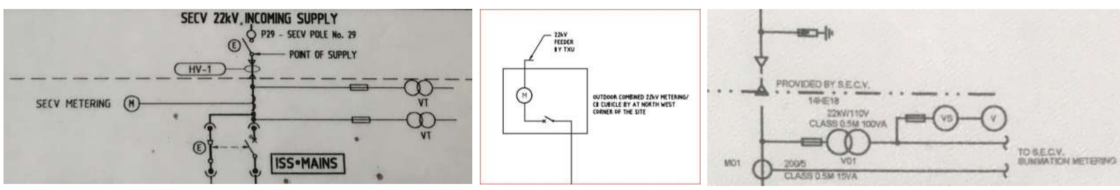
Demarcation between customer assets and network assets can be unclear

Accountability for safety requires accurate knowledge of asset ownership. In the sites visited, the point of demarcation between assets owned by the customer and assets owned by the distribution business was generally not precisely known by the local maintenance team. Teams in each site were asked the precise location of the ownership boundary. Most could not easily answer this question.

Items of information that provided guidance on the ownership boundary location included:

1. **Supply Agreements:** One site produced a copy of the original supply agreement established with the SECV[10] decades ago. This agreement specified precisely the boundary in the incoming overhead supply in terms of the last pole holding assets belonging to the distribution business and the first pole holding customer assets. Other sites visited did not offer information of this quality when asked. Network owners were able to provide copies of some supply agreements but not all.
2. **Schematic diagrams:** Some sites had schematic network diagrams showing a dotted line marking the boundary between SECV assets and customer assets. It was not always clear which assets were on which side of the line. This applied in particular to metering assets and underground cables that crossed the line as well as surge diverters at the point of supply. In some diagrams, the boundary was clear but did not match the other indicators of ownership. Typical schematic diagram treatments of the boundary are shown in Figure 10.

Figure 10: Asset ownership boundary as shown on schematic diagrams



3. **Signage:** Some sites had signage that indicated which rooms, poles or equipment belonged to the SECV and which belonged to the customer. However, some assets had SECV signage that appeared to be accidental, probably because the customer had purchased a standard SECV designed product such as a kiosk substation which came from the manufacturer with an SECV label attached as standard. In other sites, metering rooms labelled “SECV Metering” contained assets that were clearly controlled and maintained by customer staff.
4. **Keys:** In cases where the customer had no keys to access an asset, this was taken as a reasonably reliable indication that the asset concerned belonged to the distribution business rather than the customer. In some sites, the meters were in a locked cubicle that the customer could not access, while the metering transformers (which are of more relevance to this review) were embedded in customer-owned switchgear with no documentation or local knowledge of their ratings. At one site, the locked cubicle was not accessible by either the customer or the network owner, but only by a third-party metering service provider based in Queensland.
5. **Age:** Older sites tended to follow SECV standard practice where metering transformers remained the property of the SECV, though some of these assets are clearly now controlled

[10] State Electricity Commission of Victoria, Victoria’s government-owned, vertically-integrated power utility prior to disaggregation and privatisation in the early 1990s.

by customers. More recent sites tend to have had customer ownership of the metering transformers from the start.

Overall, it was concluded that this was an area of potential confusion where ownership boundaries may have become blurred by decades of local informal arrangements between customer teams and local network business employees or contractors. The ownership boundary should be clarified in order for accountability for asset safety performance to be clear.

6. Materiality of risks from customer assets

Victoria's REFCL rollout is a massive undertaking. Assets across 45 rural distribution networks must be hardened and assets incompatible with REFCL operation replaced. Work to harden networks will mitigate the risk of cross-country faults but can never completely eliminate it. A residual level of risk will remain, which prompts two questions: What is the residual level of risk in a hardened network? Further, how much might this residual risk be increased by the presence of similarly hardened customer assets?

It is likely that in many cases it will be desirable for supply reliability purposes that customer assets are hardened to a higher standard than network assets. Networks can have redundant supply paths to preserve or quickly restore supply if a network asset fails. Many customers also have redundancy but some do not and the consequences of an asset failure in those sites may be harder to mitigate. Although this is not directly relevant to the safety analysis in this project, the measures in the recommendations in Section 3 for customer assets generally match or exceed those being applied to network assets.

Residual risk in hardened networks

The primary factor in understanding the residual level of risk in hardened REFCL-protected networks is the probability of occurrence of cross-country faults on such networks. The only local data available for indicative analysis is that provided to this review by United Energy for the Frankston South (FSH) zone substation and its network which has operated for more than six years with a REFCL[11]. It is estimated this network has been exposed to REFCL-produced over-voltages more than 500 times since REFCL installation[12].

Excluding the 2014 REFCL Trial test program, the FSH REFCL confirmed 14 per cent of over-voltage events to be sustained earth faults and 77 per cent non-sustained. The remaining nine per cent cannot be confidently linked with a real earth fault or otherwise categorised for a variety of reasons.

Over the same recorded period, cross country fault events number at most six:

Two certain instances (October 2011 and June 2014):

1. Either a surge diverter or adjacent cable termination failed causing a momentary earth fault. Then a surge diverter failed on different phase (this was never located).

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[11] Prior to installation of the FSH REFCL, the FSH network was hardened in a broadly similar way to that currently being used in the rural REFCL rollout. The FSH REFCL is not operated at the 'required capacity' set out in the April 2016 regulations, but the voltages produced by FSH REFCL action equal those in any other REFCL network (albeit for less than ten seconds) and the FSH experience is considered relevant to the REFCL rollout.
[12] The FSH REFCL has displaced network voltages 362 times on the basis it has detected a network earth fault. This number excludes displacements during the 2014 REFCL Trial. It is estimated this program of 259 tests would have included about 150 full displacements and perhaps 50 partial displacements of network voltages.

2. During the 2014 REFCL Trial (Test 217) following the applied earth fault, a cable failed on another phase followed by failure of an ACR (of a design incompatible with REFCL operation). High cross-country current flow was experienced.

Two likely instances (October 2011 and December 2016):

3. One was assumed to be due to a consequential surge diverter failure (self-cleared, never located).
4. One occurred and self-cleared after the initial fault had self-cleared, thought likely to be surge diverter failure. No cross-country current flowed.

Two possible instances (December 2010 and April 2015):

5. The initial fault was identified as sustained so the network reverted to traditional NER protection, after which a transformer fuse on a different phase was reported to be found blown. If the phase was reported correctly, this may have been a cross-country fault.
6. Same as 5 above, but this time a surge diverter failure was suspected as the cause of the blown fuse.

Hypotheses arising from United Energy REFCL experience

Many hypotheses arise naturally from the historical review of cross-country faults on the Frankston South network, including:

1. Cross country faults are relatively rare, comprising perhaps one per cent of all earth faults.
2. Not every cross-country fault creates fire risk:
    a. Most (four out of six) such faults have occurred outside of fire seasons; and
    b. In the two cases that occurred during a fire season, no cross-country current was detected[13], probably because the first fault cleared before the second occurred.
3. The most common asset involved in possible cross-country faults has been a surge diverter which failed quickly from higher than normal voltage during REFCL operation.

The detailed Frankston South REFCL record also demonstrates that evidence for a cross country fault is often less than conclusive.

Failures of cables caused by higher than normal voltage is a key issue

The failure of surge diverters exposed to higher than normal voltage levels is relatively well understood. If they are going to fail, they fail quickly and the result is usually a cross-country fault, though based on FSH experience, high current flows may not occur.

However, the failure of cables due to over-voltage is a much more complex issue.

Data supplied by United Energy details eleven cable failures[14] on the Frankston South network with the REFCL in service. Eight of these occurred when the REFCL was not causing higher than normal voltages on the network.

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[13] A cross-country fault only creates safety risk (i.e. fire risk) if the first earth fault is still present. It is not entirely certain how many of the events described in the United Energy record would create such risk.

[14] Cables on the FSH network have the same voltage ratings as those in rural networks. Like rural networks, some FSH cables are older than those in most customer sites reviewed. Prior to REFCL installation, the FSH network operated with a Neutral Earthing Resistor (NER) for decades. Assets on NER networks experience

Apart from the cable failure during Test 217 of the 2014 REFCL Trial, two other cable failure events in the FSH records are potentially relevant:

- February 2015: Cable failure shortly after a high impedance fault on another phase.
- April 2015: Cable failure 20 minutes after a high impedance fault on another phase.

The fact that only three of eleven cable failures can be linked to over-voltages caused by REFCL action indicates that cable failures do not appear to be strongly correlated with REFCL presence. United Energy reports the difference between post-REFCL and pre-REFCL cable failure rates is not significantly greater than normal year-on-year fluctuations. This is consistent with at least one international comparison of XLPE cable failure rates which shows that Europe (REFCLs) has lower cable failure rates than North America (no REFCLs)[15] - in fact, far lower.

A brief review of other reported international research on failure rates of XLPE cables, supported by discussions with local cable experts, provides the following valuable perspective:

- The first generation of XLPE cables were manufactured using steam curing. In later failure investigations, this was found to have created microscopic water-filled voids in the insulation which led to progressive insulation deterioration and shortened the service life of the cables, sometimes to 25 years or less.
- Steam cured XLPE cables were manufactured in Victoria up until Nylex/Olex/Nexans changed to dry Nitrogen curing in the early 1980s. The other two local cable manufacturers followed by 1990. It is relevant that AusNet found five of the eight cables PD tested at Woori Yallock zone substation failed the tests – these cables are thought to have been installed around 1982, which means they may have been steam-cured.
- Dry-cured XLPE cable has a ten times lower failure rate which extends typical cable service lives beyond 40 years. Failures in these cables are more likely to be in joints and terminations rather than in the cable itself. This is consistent with test results and cable failures in the REFCL rollout to date.
- Modern XLPE cables (termed 'super-clean') are dry-cured in plants with a much higher standard of cleanliness spanning the whole supply chain. These have even lower failure rates and even longer service lives.

Local cable experts opine that the majority of failures in cable installations using Australian-made cable manufactured since 1990 are joint failures caused by water ingress. This view is supported by comments from network owners. Cable experts believe cables locally manufactured since 2000 and installed using the advanced jointing technology available since then should easily withstand the higher than normal voltages produced in REFCL operation. Those manufactured in the 1990s are also likely to do so with a slightly higher failure rate, primarily due to less advanced jointing technology.

International experience supports this story. Danish experience[16] with cables in REFCL networks indicates about half of all cable failures occur during the period of higher than normal voltage (which in Denmark can last for hours) and about half occur at normal voltage levels. Only 20% of the failures

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higher than normal voltage levels during high-current earth faults, albeit for periods of less than one second. Whether this has pre-hardened the FSH network by 'weeding out' vulnerable cable assets is a possibility this project has not addressed. The authors are not aware any pre-REFCL cross-country faults on the FSH network.

[15] The ageing of extruded dielectric cables. Jicable/EPRI/CEA workshop 1989 Paper 5f. The authors of this paper spell out the challenges of drawing reliable conclusions from the comparison of cable failure rates.

[16] 2013 CIRED Stockholm, Paper 1152, Jens Zoëga Hansen, *Results from Danish failure statistics for medium voltage XLPE cables.*

during periods of higher than normal voltage have occurred quickly – the rest can take up to two hours of over-voltage exposure before they occur.

Some cable failures on the Frankston South network appear to have been triggered by higher than normal voltages caused by REFCL operation, whereas others seemed to occur after a considerable delay, i.e. consequential cable failures may not create a cross-country fault, they may happen after network voltages have returned to normal and so be seen by the REFCL as a separate earth fault. Unlike Danish network companies, United Energy limits the duration of the higher than normal voltage produced by the FSH REFCL to less than ten seconds. Taking this into account, the experience at Frankston South appears broadly in agreement with that reported for Denmark.

This very brief review of cable failure information supports the following hypotheses about cables in hardened REFCL networks:

1. REFCLs do not materially increase the failure rate of cables and may even reduce it;
2. REFCL operation can trigger a cable failure that was about to happen anyway; and
3. Only a small fraction of cable failures associated with REFCL action are likely to be cross-country faults; most occur after the original fault has gone and so constitute a new fault.

If these observations are correct, cable failures may be more likely to create risk of supply outages and interruptions to customer production than they are to create fire risk or asset damage.

Risks from customer cable assets

The customer sites reviewed were found to be rich in cable assets. The twelve sites contained 112 cable segments (which implies 650 terminations and an unknown number of joins) totalling more than 19 kilometres of cable. The age profile of the XLPE cables and the associated level of cable failure risk based on the considerations above is shown in Table 1.

Table 1: Estimated failure risk of customer XLPE cable assets and appropriate mitigation action[17]

Number of cables	Total length	Manufacture	Risk	Default action
34	5.3 kilometres	Post 2000	Low	Nil
46	6.7 kilometres	1990s	Low[18]	Test
24	7.0 kilometres	1987	Medium	Test
2	30 metres	Pre-1980	High	Replace

The review rated four cables as indicated for replacement, plus a further 43 for testing. No action seems warranted for 64 cables.

If published 1989 UNIPEDE XLPE cable failure data for Europe[19] is taken as a guide, the 200 kilometres of customer-owned XLPE cable in Victoria's REFCL-protected networks should suffer one failure every 4.2 years on average. North American data (non-REFCL networks) would suggest one failure every six months. Given the cables reviewed in this project have all been in service for a long period in non-REFCL networks, the North American figure may be more relevant. The failure rates

[17] Three cables totalling 100 metres were paper/oil insulated and more than 50 years old.

[18] Though failure risk is low for cables of this age, joints and terminations are less certain so the recommendation is to test them - hence their inclusion in the 'medium risk' category shown in Figure 7.

[19] K Leeburn, CBI-electric, African Cables, South Africa: *Tracking the evolution of XLPE and water trees JICABLE 1984 – 2011*, E+C Spot On.

behind these numbers are averages over all installed cables and the mean time between failures may be shorter for the cohort of customer-owned cables in Victoria, which the review indicates is likely to have a mean age of 22 years.

Based on the Danish research referenced above, though about half the failures may be triggered by REFCL operation, only ten per cent are likely to happen fast enough to cause a cross-country fault within Victoria's much shorter periods of over-voltage from REFCL operation.

This logic leads to an estimate that after completion of the REFCL rollout, Victoria might expect a handful of customer cable failures a year with one cross-country fault from a customer cable failure every few years provided customer cables are hardened to REFCL standards. The default approach to hardening of cables could be:

1. No action on post-2000 cables (apart from normal REFCL commissioning 'soak' tests)
2. Test cables manufactured between 1980 and 2000 and replace those that fail tests
3. Replace cables manufactured prior to 1980.

All of the above is based on very scant information and many assumptions. It would be valuable for local network owners to collect and share data on cable failures to refine the approach over time.

Increase in residual risk from customer assets

Customer assets may add an additional safety risk of about three per cent to the residual risk in the REFCL distribution networks. This is an indicative 'order of magnitude' estimate based on comparative asset numbers in customer sites and rural distribution networks as set out in Table 2.

Table 2: comparison of customer asset numbers with network asset numbers

Asset type	12 customer sites	130 customer sites	9 rural networks[20]	45 rural networks	Customer assets as % of total	Weighting[21] (% of FSH CC faults)	Added risk
Cable	19 km	205 km	227 km	1,135 km	18.1%	15%	2.7%
Transformer	85	920	9,227 eq	46,135 eq	2.0%	15%	0.3%
Surge div	25	271	27,428	113,300	0.2%	70%	0.1%

Even though this estimate relies on a number of assumptions and extrapolations, it provides a useful preliminary insight into the materiality of the issue.

Table 2 indicates that cable failure risk dominates the estimated three per cent increase in overall risk of cross country faults. It was clear from the site visits that customer sites are rich in cables and poor in surge diverters compared to rural distribution networks. This suggests the focus of risk mitigation should be on cables once obvious issues like under-rated surge diverters and voltage transformers have been addressed.

[20] The nine networks used for this extrapolation are the AusNet networks in Tranche 1 of the rollout: WYK, RUBA, BWA, WGI, KLK, WN, SMR, MYT, KMS. The equivalent number of network transformers is the total number of transformer bushings divided by three to account for both three-phase and single-phase transformers.

[21] The comparative risk arising from each asset type is weighted to reflect the involvement of that asset type in the six possible cross-country faults experienced to date on United Energy's Frankston South (FSH) network.

7. Risk from customer assets is similar to that from network assets

Risk may arise if a high voltage asset does not have the capability to withstand the over-voltage produced by REFCL response to a fault. This is independent of ownership of the asset. All customer assets reviewed were found to have been manufactured in accordance with appropriate Australian or reputable international standards. The majority were in accordance with SECV standards of the day and some were products designed for sale to the SECV, having SECV signage still on them.

Asset failure mode is insulation break-down reached by a diversity of paths

Assets that give rise to potential safety risks from cross-country faults fall into two groups with diverse paths to the single ultimate failure mode of insulation break-down:

- High voltage cables and supply transformers: these can fail from break-down of high voltage insulation due to age-related and cumulative overload-related deterioration as well as possible cumulative damage from partial discharge during previous periods of over-voltage.
- Surge diverters and voltage transformers: these have two over-voltage failure modes – insulation break-down as described above and over-heating due to increased current flow through them. This heating can lead to insulation break-down and in the case of surge diverters, thermal runaway in which a normally low leakage current can reach fault current levels.

There are two aspects of any particular asset that set the risk of failure under over-voltage conditions: specification and condition.

Specified over-voltage ratings apply at the time of asset purchase

Most high voltage assets are purchased to meet technical standards that include three over-voltage ratings: the rated continuous operating voltage, the one-minute over-voltage withstand test voltage and the Basic Impulse Level (BIL)[22].

Ratings of customer assets were found to be in most cases identical to those of assets on the network supplying the site. Over-voltage ratings were 50kV one minute withstand and 24kV continuous operating voltage. Such ratings would normally be considered suitable for procurement of assets to operate on a 22kV REFCL-protected network.

Impulse ratings of customer assets were generally either 125kV or 150kV. Some transformers at one site were rated to only 90kV BIL. However, these were still rated to 50kV over-voltage withstand.

Voltage transformers and surge diverters use voltage ratings that differ from other asset classes to address their additional failure mode of over-voltage heating. Because they are normally connected between the phase conductor and earth, the usual 24/50/150kV ratings are less applicable. A voltage transformer for a REFCL network should be rated to “1.9Un/8h”, i.e. they should be able to survive a 90% over-voltage for eight hours. A surge diverter for a 22kV REFCL network will usually be satisfactory if rated to operate at a continuous voltage level of 24kV, i.e. 90 per cent above nominal.

[22] The BIL is more relevant to lightning strikes and switching surges than to REFCL-produced over-voltages.

Current over-voltage withstand capability can only be proven by test

Specified ratings offer assurance of low risk only if the over-voltage withstand capability has not materially deteriorated though asset age and heavy use over a long period. Tests can provide an indication of whether this has occurred.

If the asset is a transformer, DGA[23] of an oil sample can reveal the presence of insulation break down products. Many customers perform regular DGA tests and some also do Furan tests on the oil to determine if there are faults in the transformer and the degree of degradation of the insulation.

If the asset is a cable or item of metal-clad switchgear, PD[24] tests can reveal if it will withstand the over-voltages produced by REFCL operation and further, if such over-voltages are likely to create a risk of accelerated deterioration of the high voltage insulation.

There is always a risk in undertaking over-voltage tests of old equipment – it must be done carefully and not often. None of the assets reviewed have been subjected to PD tests.

Testing of cables, cable joints and terminations involves complex issues

If the asset is a cable, PD tests will reveal some types of over-voltage vulnerability, but not all types. Particularly older steam-cured XLPE cables can fail through the slow growth of 'water trees' in the plastic insulation. These water-filled voids progressively grow over decades at a rate related to voltage stress on the cable. Only in the very final stage of 'tree' development, when it is within millimetres of reaching all the way from the central high voltage conductor to the outer earthed screen, will PD tests reveal the risk. By that stage, cable failure is imminent even at nominal voltage level.

If a high level of network hardening assurance is desired, old steam-cured cables vulnerable to this type of failure should be considered for replacement regardless of PD test results. However, as FSH network experience demonstrates, this type of failure is likely to happen randomly rather than as an immediate result of a REFCL producing higher than normal voltage, so it may not often cause cross-country faults and hardening may be more relevant to customer supply continuity than safety.

This reality applies less to cable joints and terminations and PD tests are thought to more reliably reveal vulnerability of these items to higher voltages. There is very little data on joint failures, but it is possible they are more likely to cause cross-country faults than are cable failures. PD tests on cables should be viewed as tests for cables in already degraded condition and of the associated joints and terminations. PD tests of the 64 low-risk cables shown in Figure 8 may be of value if a high level of hardening assurance is required.

As with all tests, there is no guarantee that if an asset passes the test it will not fail during future REFCL operation. All a successful test does is show the asset was satisfactory at the time of the test.

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[23] Dissolved Gas Analysis (DGA) reveals the presence of gases such as methane and hydrogen which result from insulation break-down. This is the most reliable non-intrusive test of insulation condition in oil filled assets.
[24] Partial Discharge tests at elevated voltage detect tiny discharges of electricity in small voids in insulation. However, some sources of PD are relatively benign and do not indicate degraded insulation. All over-voltage tests on old assets, such as PD tests, should only be done at or slightly above the maximum voltage expected from REFCL operation and the test should only last as long as REFCL voltage displacement is planned to last.

Risk mitigation options are the same but customer/network asset mix differs

Mitigation options to minimise safety risk from customer assets are the same as those facing owners of network assets. These include initial replacement of REFCL-incompatible assets, followed by regular inspection, tests and maintenance. If safety risks are to be well managed, the asset management strategy should address the goal of confirming and preserving asset capacity to withstand the high voltages involved in REFCL network operation.

The review revealed that customer assets comprise a different mix to network assets. In customer sites, underground cable is comparatively more prevalent and surge diverters and protection VTs are less prevalent. However, the individual assets were in many cases the same. It is also relevant that in many customer sites, the underground cables are younger than some found in networks.

Every customer site has at least one set of metering voltage transformers (VTs) and current transformers (CTs) that must be included in risk considerations. For two reasons, network owners may not yet have fully recognised the issues associated with metering transformers. Firstly, ownership of these assets appears to be unclear in many sites; and secondly, REFCLs installed to date are on networks with few if any customers that take supply at high voltage.

While ownership of the actual meters was found to be usually clearly defined by the party who has the keys to open the cubicle in which they are contained[25], ownership of the metering transformers that supply voltage and current signals to the meters was far less certain. Sometimes these were embedded in customer switchgear but the customer knew nothing about them. In other cases, they were pole-mounted inside or outside the boundary fence. Some of the metering transformers reviewed were clearly owned by the customer, some clearly owned by the network business[26] and the rest were of uncertain ownership.

8. Customer asset management is generally at least as good as network asset management

With a few exceptions, customer assets were observed to be in good condition and asset maintenance was observed to be in accordance with good industry practice. If the quality of the reviewed asset management programs is taken as a guide, the condition of customer assets should be at least as good as assets in the networks supplying them.

Maintenance funding is accepted, capital spending is challenged

Regular test and inspection regimes are in place covering all the customer assets reviewed. Electrical supply is usually critical to plant production and the loss-of-production cost of supply outages from asset failure can be very high, so asset maintenance activity is given a commensurate degree of priority. Despite this, no sites had backup power supply[27] for anything more than stock preservation (e.g. refrigeration supplies) and some had assets that constituted obvious single points of complete supply failure with long restoration times.

[25] In some sites visited, this was not the local distribution business but a third-party metering service provider.
[26] If clearly owned by the network business, they were excluded from the analysis reported here.
[27] Two sites had large back-up generators, but neither could maintain all normal site operations without network supply.

All site maintenance teams reported stringent capital management with asset replacement accorded a relatively lower priority in competition for capital budget compared to assets that increase production capacity. However, some sites are contemplating significant electrical asset replacement and rationalisation in the near future, generally associated with identification of failing assets or major expansions of the plant.

Asset maintenance skills and information management are good practice

Typically, asset maintenance on each site is managed by a local team with para-professional electrical skills at the electrician special class or engineering associate level plus a specialist contractor engaged to carry out a regular test program. Team size matched site size and complexity. Team attitudes displayed a dedicated commitment to keeping plant running by finding and fixing problems before they interrupted production.

Asset information management was generally very good and in some cases, exemplary. Weaknesses tended to be associated with metering assets where ownership was unclear.

Power transformer test regimes were often better than for network assets

In most sites, the regular asset test regime included basic Megger tests of insulation integrity, thermal scans and DGA tests of all power transformers. DGA test intervals for the transformers reviewed ranged from six months to five years (longer for newer transformers), though a few customers did no DGA tests at all. None of the assets reviewed had been subject to PD tests to assess insulation condition.

By comparison, distribution businesses use fixed-interval inspection-based (visual, thermal and corona scans) maintenance programs covering network assets. With some exceptions, these do not include DGA testing of power transformers outside zone substations. PD tests of network cables are generally only done when age and increased rates of failure indicate replacement is likely to be required in the short term.

9. Risks can be cost-efficiently mitigated

Although this was not a specified objective, the review has provided some insight into the potential cost of mitigation of any safety risk associated with customer assets.

Isolation transformers may the highest cost option in many cases

The option of a site-boundary supply isolation transformer between the customer site and the distribution network has been widely raised by the local network industry in discussions relevant to cross-country fault risk from customer assets.

This review indicates that isolation transformers are unlikely to be the lowest cost way to mitigate safety risk associated with the customer assets reviewed, recognising that factors other than cost may influence the ultimate decision – in particular, an isolation transformer may remove any requirement for action by the customer and cost recovery may be shared by all customers of that network.

The review included only one or two possible exceptions to this high level cost comparison - the largest and most complex sites. Even in those cases, it is not clear an isolation transformer is a compelling least-cost proposition compared to other approaches. Certainly, isolation would be much higher cost that the hardening solutions being used for the same types of assets on the distribution networks.

Table 3 illustrates the issue. It shows in very approximate terms the estimated hardening costs of eight sites[28]. Four costing options are shown:

1. Replace all cables on the site.
2. As above, with financial recognition of the already expired life of the cables[29].
3. Replace only those cables on the site where tests show this is warranted.
4. As above, with financial recognition of the already expired life of the cables[29].

The costs for each site also include replacement of surge diverters and voltage transformers where the review has indicated this is likely to be required.

Table 3: Site hardening cost estimates ($ millions)[30]

Site	Replace all cable		Replace selected		Assumed selected cables replaced
	No rebate	Rebate	No rebate	Rebate	
A	3.04	1.80	1.66	1.04	50% of 30yr old cables
B	2.64	1.85	0.72	0.56	20% of 22yr old cables
C	1.14	1.05	0.07	0.07	One 50+ year old cable
D	0.58	0.29	0.22	0.15	50% of 27yr old cables
E	0.51	0.38	0.47	0.30	
F	0.30	0.22	0.01	0.01	
G	0.06	0.06	0.06	0.06	
H	0.02	0.02	0.02	0.02	

The estimated costs shown in Table 3 should be compared with a site-fence isolation transformer, estimated to typically cost between one and three million dollars. It is clear that hardening costs are generally lower than the cost of isolation. On a least-cost basis, only one of the reviewed sites would warrant consideration of an isolation transformer and for that site the maximum demand is such that an isolation transformer may be beyond the high end of the cost estimate range.

Other factors in the choice between hardening and isolation

This project did not consider factors other than cost in the 'isolation versus hardening' choice. Specifically, it did not cover:

- Liability and regulatory considerations;
- Economic and financial consequences of supply reliability factors;
- Compliance with Victoria's Electricity Distribution Code without any requirement for negotiation;
- Specialised technical requirements[31]; and

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[28] The other four sites are for transport and water infrastructure and costs were not estimated for these.
[29] Value allocated linearly over 40 year service life.
[30] These estimates include procurement, installation, clean-up, etc., but do not include the costs of initial audits and tests to assess asset vulnerability to over-voltage. This would add an amount ranging from zero for small simple sites to perhaps $200,000 for the most complex sites if facilitated by network owners.

- Alignment with REFCL rollout timelines.

Customer representatives in on-site discussions were generally supportive of early hardening action and less aware of (or interested in) isolation options. However, this may not reflect a more fully considered corporate position on the issue.

With a fixed rollout timeline, lead times for works may influence decisions

Any differences in lead times between isolation and hardening options will only be known when engineering designs and procurement lead times are determined. However, both can be expected to involve significant times for design, procurement and commissioning of the required assets. Further, commissioning of any new assets may have to await suitable production halts.

The dates when network owners must comply with the new bushfire safety regulations are set out in the April 2016 legislation. Network owners may apply to have these dates varied and ESV has defined powers to approve variations in specified exceptional circumstances.

In most of the reviewed sites, on-site customer representatives observed there had not yet been significant discussions between them and the network owner on options to manage risks associated with REFCL implementation. Such discussions should not be expected to be onerous - this review produced reasonably reliable initial assessments of risks and options for even a large complex site after about five hours of desk research and a three-hour site visit. Clearly, the earlier such discussions get underway, the less will project lead times be a challenge.

Changed operational practices may be an option for some customers

For some of the reviewed assets, changed operational practices may be a practical option to manage safety risks – some customer infrastructure may not need to remain connected at times of high fire risk, e.g. Total Fire Ban days. These customers may agree to this infrastructure being isolated at times of high risk. This approach may be viable for micro-hydro generators and some specialised high voltage supplies for occasional operations such as product testing. Other sites indicated that supply outages on Total Fire Ban days would not be acceptable. This would not impact normal REFCL operation on non-TFB days as safety risk is greatly lessened at those times.

Surge diverter replacement is likely to be a lower cost item

Most customer sites have many fewer surge diverters than is common on distribution networks and some have none at all, so surge diverter replacement is likely to be less of an issue. Where it is indicated, it may involve lower costs as some customer-owned surge diverters are at ground level in kiosk structures and metal clad switchgear.

[31] For example, Melbourne's electric rail transport requires all its substations to be supplied at the same phase angle as they use the network voltage (stepped down) for signalling purposes. They could not easily adapt to having some sites at a different phase angle introduced by unsuited isolation transformer designs.

Aged cables may be the highest cost item but their condition is untested

The primary driver of potential risk mitigation costs is likely to be the unknown condition of aged high voltage cables and cable joints and terminations on the customer's site[32]. Early action to test the condition of these assets would be advisable to reduce uncertainty. Many of the sites reviewed had relatively short runs of HV cable, some of which was in cable trays rather than underground. Some sites have some cables in the 30-40 years age range, while others have much younger cables. A few had runs of very old cable of uncertain age and of types that predate modern XLPE cable technology.

Only PD tests will reveal whether customer XLPE cables must be replaced. No PD tests have been performed on any of the cables reviewed. In REFCL commissioning to date, network owners have generally only done PD tests on cables within the zone substation (e.g. transformer cables) and on feeder exit cables. PD tests on other cables located 'out on the network', e.g. in housing estates, have tended to be done only to check cables that are nearing the end of their service lives as indicated by increasing fault occurrence.

For older (pre-XLPE) paper-insulated cables, PD tests are more difficult and less conclusive. Tests of moisture levels may offer some value in assessment of insulation strength in such cables.

If required, asset replacement is a brought forward (not a new) expense

Many customer assets reviewed (especially cables and transformers) were observed to be of an age well into a normal service life – refer Figure 9 on page 11. However, their original ratings and specifications would indicate they would be suitable for REFCL networks if new. In such cases, should tests indicate replacement is required, the mitigation cost associated with REFCL rollout perhaps should be the cost of bringing forward the asset replacement rather than the full cost of the new asset. In Table 3, this is reflected in the 'rebate' columns.

Metering transformers are an unknown quantity

Risk associated with customer-owned voltage transformers is more complex than originally thought and further consideration and possibly testing may be warranted to clarify it. In some sites, replacement may not be required. Where replacement is required the cost may not be high – typically less than twenty thousand dollars. It is thought the majority of are of the "three single-phase units" configuration. Some sites reviewed, particularly older ones, had no protection voltage transformers, only metering ones. Those that did have both, tended to have them embedded in modern metal-enclosed switchgear.

Mitigation costs can be further reduced by early action

Customers that take supply at high voltage tend to be large complex organisations. Multiple levels of communication are essential. The most productive value may be derived from communication directly with onsite electrical maintenance teams and capital works planners – this should proceed in parallel with corporate level communication.

[32] The same would be true of customer power transformers except that most customers maintain regular DGA testing so their insulation condition is better known.

Actions can be taken now to reduce longer term costs. For example:

- Publication of "REFCL-compatible" equipment ratings to guide customer asset purchases. These should cover surge diverters, voltage transformers, power cables and power transformers as a minimum.
- Facilitation of cable PD testing. Customers are unfamiliar with this type of test and would benefit from guidance and support to test their assets where indicated.

10. Conclusion

This initial indicative risk survey of a small sample of customer infrastructure directly connected to the distribution networks included in Victoria's REFCL rollout has provided useful insights into the drivers of risks and the two broad options to preserve the fire risk reduction benefits of the rollout – isolation or hardening.

As the rollout progresses, this preliminary understanding should be further refined and extended to optimise the approach to management of customer assets connected to these networks, taking into account the diversity of interests of the many stakeholders involved.

