



Supporting
document 5.6

Northfield 66kV GIS Replacement Business Case

2020-25 Revised
Regulatory Proposal
10 December 2019



SA Power Networks



Northfield 66kV GIS Replacement Business case

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Document Control

Version	Date	Author	Notes
1.0	6/12/2019	Mark Pritchard James Fry	

Summary

This business case recommends \$11.2 million (\$, 2018 excluding corporate overheads) of capital expenditure be provided to replace the Gas Insulated Switchgear (GIS) at the Northfield Substation. This amount is equivalent to \$11.7 million in real \$2020 terms which has been included in the Replacement expenditure forecast contained within SA Power Networks Revised Proposal.

Northfield Substation is a critical supply point for Adelaide's Eastern Suburbs' electrical supply, feeding 108,000 households and businesses. It is a Connection Point shared between SA Power Networks (the Distribution Network Service Provider) and ElectraNet (the Transmission Network Service Provider). The transfer of power between ElectraNet and SA Power Networks occurs at 66kV and uses Gas Insulated Switchgear (GIS), which is owned and operated by SA Power Networks.

The 66kV switchgear at the Northfield Substation was built in 1988. After 30 years of continuous service in an outdoor environment, it is presently in very poor mechanical condition and subject to accelerated aging. There is significant external corrosion which has initiated five failures of gas seals, resulting in the uncontrolled atmospheric release of sulfur hexafluoride gas (SF₆). It's now apparent this GIS was not well suited to an outdoor environment.

Gas leaks, if not addressed, can lead to forced outages of the GIS or worse, catastrophic failure. The key risk associated with the failure of the 66kV GIS installation at the Northfield Substation is the loss of reliability and security of supply to the Eastern suburbs of Adelaide. The impact includes:

- An initial customer outage, from 22,000 up to 108,000 households.
- A continuing inability to meet peak demand for two years until a replacement is built (approximately 16,000 households would be without supply for 16 of the peak hot summer evenings over the two-year period).

Other major issues include:

- Environmental concerns, resulting from the release of SF₆ gas into the atmosphere.
 - While there are no current penalties associated with the release of SF₆ gas, there are potential reputation risks faced by SA Power Networks (and potentially the broader electricity sector).
 - SA Power Networks could also be at risk of violating section 79 of the Environmental Protection Act 1993 (SA) through causing environmental harm, as it is aware that the failures of the Northfield GIS Substation assets are causing leakages of SF₆, which by all reasonable estimates are expected to worsen without maintenance intervention.
 - There is also growing regulatory pressure internationally to ban the use of this gas in new switchgear and increasing pressure to reduce leaks from existing in-service equipment.
- The high costs of ongoing gas leak repairs.

With over 200 joints (400 flanges) as potential locations for leak sources, there is an identified need to address the present and long-term risks associated with the operation of the 66kV GIS installation at Northfield Substation to avoid widespread outages and forced load shedding in summer. The internal condition of the GIS is unknown and is unable to be assessed but given the level of external corrosion it is highly likely that additional gas leaks will occur. Unlike many other electrical distribution assets, it is not possible to quickly affect component repairs or replacement of major failures to GIS substations of this type. Rather, it would be necessary to build an equivalent replacement, which would take in excess of two years.

SA Power Networks has considered four options for addressing the risks associated with the 66kV GIS at Northfield Substation, being:

- Option 1: Replace the GIS on failure (base case).
- Option 2: Full replacement with Air Insulated Switchgear (AIS) in 2023.

- Option 3: Partial replacement with AIS in 2023, deferring half the Capex of a full AIS replacement.
- Option 4: Full replacement with GIS in 2023.

SA Power Networks has considered other demand- and supply-side options. However, these options were not deemed credible for a range of reasons, including most notably, the fact that the load at risk (321 MVA) could not be supplied from generation sources that could be mobilized in the event of failure, as well as the length of time to develop programs and the associated high costs.

Attempts to externally seal SF₆ leaks from the GIS, as recommended by independent parties and facilitated by the manufacturer, have had poor success. Opportunities to undertake these repairs are limited to a few weeks a year due to the critical function of the asset. More invasive repairs have been considered; are high cost and carry an extreme risk of further damaging the already deteriorated GIS. SA Power Networks does not consider these options credible as they are neither cost-effective nor prudent.

Consistent with the Australian Energy Regulator's (AER's) RIT-D Guidelines,¹ SA Power Networks ranked each credible option based on each option's present value of costs for the sum of the: value of customer reliability (VCR); and capital and operating costs. This analysis indicated that Option 3 partial replacement with AIS in 2023 and deferring the remainder of the capex until full GIS failure was the preferred option.

Option 3 has a comparable VCR to Option 2, full replacement but the second lowest total capital and operating costs. Compared to the base case of continuing to operate the GIS, this option provides a net benefit of \$7.595M.

Present value of costs, over a <u>30-year</u> evaluation period	VCR (\$M), FY2018 terms	Capital and Operating Costs (\$M), FY2018 terms	Total costs (\$M), FY2018 terms	Net Benefit compared with base case (\$M)	Ranking
Option 1: Replace GIS on failure	\$15.316	\$21.174	\$36.491	\$0	3
Option 2: full replacement of GIS with AIS	\$5.635	\$26.440	\$32.075	\$4.415	2
Option 3: partial rebuild of GIS with AIS, then defer half AIS expenditure	\$5.515	\$23.381	\$28.896	\$7.595	1
Option 4: full replacement of GIS	\$8.056	\$31.984	\$40.039	\$-3.549	4

¹ AER, (2018) *Application guidelines: regulatory investment test for distribution*, December 2018

Option 3 is the most preferred option as it provides a prudent risk management approach to the risks associated with the substation:

- Defers capital expenditure for 5 years or more until the total replacement of the AIS is required.
- The highest net market benefit and the second lowest economic cost of all credible options considered.
- A multi-staged approach which enables maximum deferral of half the capex associated with a complete rebuild, while mitigating most of the reliability and security risk.
- Building part of the final replacement solution in 2023 minimises the consequences if the existing GIS fails unexpectedly, or the condition deteriorates beyond an appropriate level to keep it in-service.
- Improved restoration times and removal of overload risk.
- Finalising the replacement solution at a time when the performance or condition of the existing GIS makes it unacceptable to keep it in-service, taking advantage of any design or efficiency improvements.

Sensitivity analysis was undertaken on the key parameters impacting the cost assessment of each option, including the discount rate, capital costs, value of customer reliability, GIS failure rates and the costs of gas leaks. The analysis indicated that Option 3 remains the preferred option over the range of values tested.

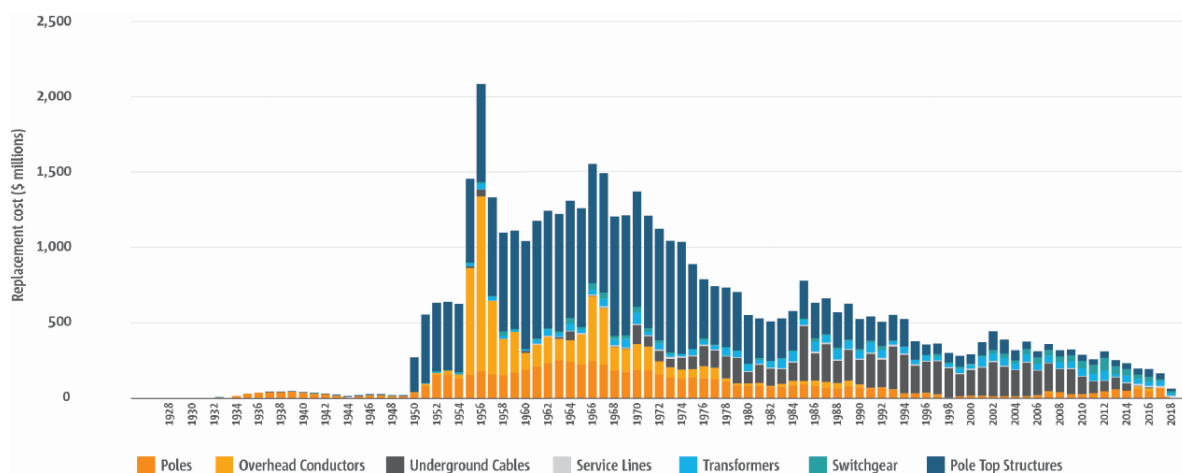
The total capital cost to SA Power Networks for this project is estimated to be **\$12.5 million (FY2018 terms including all overheads)**. This assumes that the remaining 66kV GIS does not deteriorate more rapidly and that the gas leak repair actions and maintenance corrosion treatment can slow down the rate and quantity of future gas leaks. It also includes short-term interventions and ongoing maintenance costs to address the deteriorating condition of the flanges and gas leaks.

Introduction

SA Power Networks is the sole electricity distributor in South Australia. It delivers electricity to the State to approximately 1.7 million people and 900,000 homes and businesses. The network is made up of poles, conductors and substations to distribute electricity. SA Power Networks is committed to managing its assets to continue to meet the current service standards of reliably, safely and efficiently.

SA Power Networks network has the oldest electricity infrastructure in the National Electricity Market (NEM), with the majority of assets having been built in the period between 1950 and 1970. SA Power Networks employs sound asset management strategies to maximise the life of assets while achieving target network performance outcomes. However, it is now at the risk of entering a phase of declining reliability and costly reactive asset replacements for network assets with equally well planned and timely asset replacement programs. A significant proportion of the asset base value is between 45 and 60 years of age as shown in Figure 1 which corresponds to the period when major electrification of South Australia happened.

Figure 1: Asset Age Profile²



As the assets age the risk to supply reliability increases. The Northfield 66kV GIS was built in 1988 and is presently in very poor condition. There is significant external corrosion present after over 30 years of continuous service in an outdoor environment and the key risk if the switchgear fails is the loss of reliability and security of supply to the Eastern suburbs of Adelaide.

SA Power Networks is subject to economic and other regulation. As it is part of the NEM, it must comply with the Australian Energy Market Commission (AEMC) requirements, the National Electricity Objective and the National Electricity Laws. It also has a number of obligations under various Commonwealth and State Acts, codes of practice, rules, procedures and guidelines, including:

- *Electricity Act 1996 (SA)*
- *National Electricity Law (Cth)*
- *National Energy Retail Law (South Australia) Act 2011 (SA)*
- *National Electricity Rules*
- *National Energy Retail Rules*
- *SA Electricity Distribution Code*
- *National Metrology Procedures*
- *Requirements of the license issued by the Essential Services Commission of South Australia (ESCOSA), and*
- *Australian Energy Regulator (AER) Guidelines.*

² SA Power Networks (2019) Attachment 5: Capital expenditure, 2020-25 Regulatory Proposal, 31 January 2019

This business case relates to interventions at the Northfield Substation to mitigate the reliability, security of supply, and service standard conditions which result from the deteriorating mechanical condition of the 66kV Gas Insulated Switchgear (GIS) at the substation site. It is also to address the environmental considerations which arise as a result of increasing SF₆ leakages from flange seal failures at the site. This business case has been prepared in-line with the Australian Energy Regulator's (AER's) 2018 RIT-D application guidelines (the RIT-D Guidelines).

Identified Need

The Northfield substation services 108,000 predominantly residential dwellings, with only one other supply point from Magill rated at less than half peak demand. Failure of the Northfield substation would result in tens of thousands of customers without supply initially, and a shortfall in capacity resulting in approximately 16,000 customers without supply for 16 hot summer evenings until a replacement is constructed 2 years later.

The identified need to mitigate this reliability and security of supply consequence is the rapidly deteriorating mechanical condition of the 66kV GIS at the Northfield Substation. External corrosion is highly prevalent and multiple gas leaks have developed over the last 3 years, with limited repair success. The internal condition of the GIS cannot be assessed, and with over 200 joints as potential leak sources the GIS has an increased likelihood of failure beyond repair within the next RCP. The objective is to ensure continuous supply over peak periods and ensure there are no outages as a result of the 66kV GIS at the site.

Background

The Northfield 66kV GIS

The Northfield Substation is a major site for SA Power Networks and plays a critical role in the State's power infrastructure. SA Power Networks owns the 66kV GIS infrastructure at the site. It was installed in 1988 and supplies the Adelaide Eastern suburbs network. The 66kV GIS switchboard is supplied from three 275/66kV transformers which connect the 66kV system to the ElectraNet 275kV transmission network.

There are approximately 108,000 customers supplied by the 66kV loop of ten zone substations shown in Figure 2. These are supplied by two transmission bulk supply points; Northfield with 4 66kV lines (and 2 radial loads) and Magill with 1 66kV line. The peak load for the Eastern Suburbs is approximately 321 MVA. The single Magill 66kV line with a total capacity of only 140 MVA could not supply this demand if Northfield was to fail. A temporary bypass would be built to bring additional supply in from Dry Creek (outside the loop) but would take at least one day to construct and after completion capacity would still fall well short of the peak 321MVA.

Figure 2: The Eastern Suburbs 66kV supply loop schematic

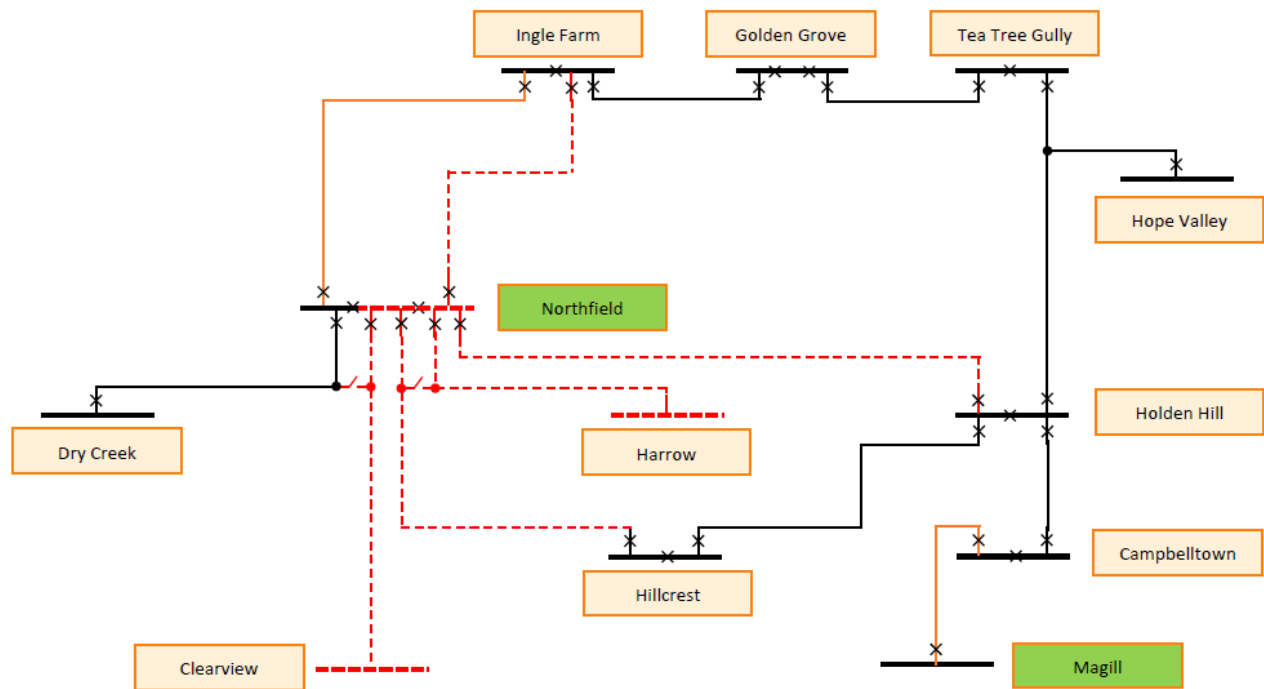
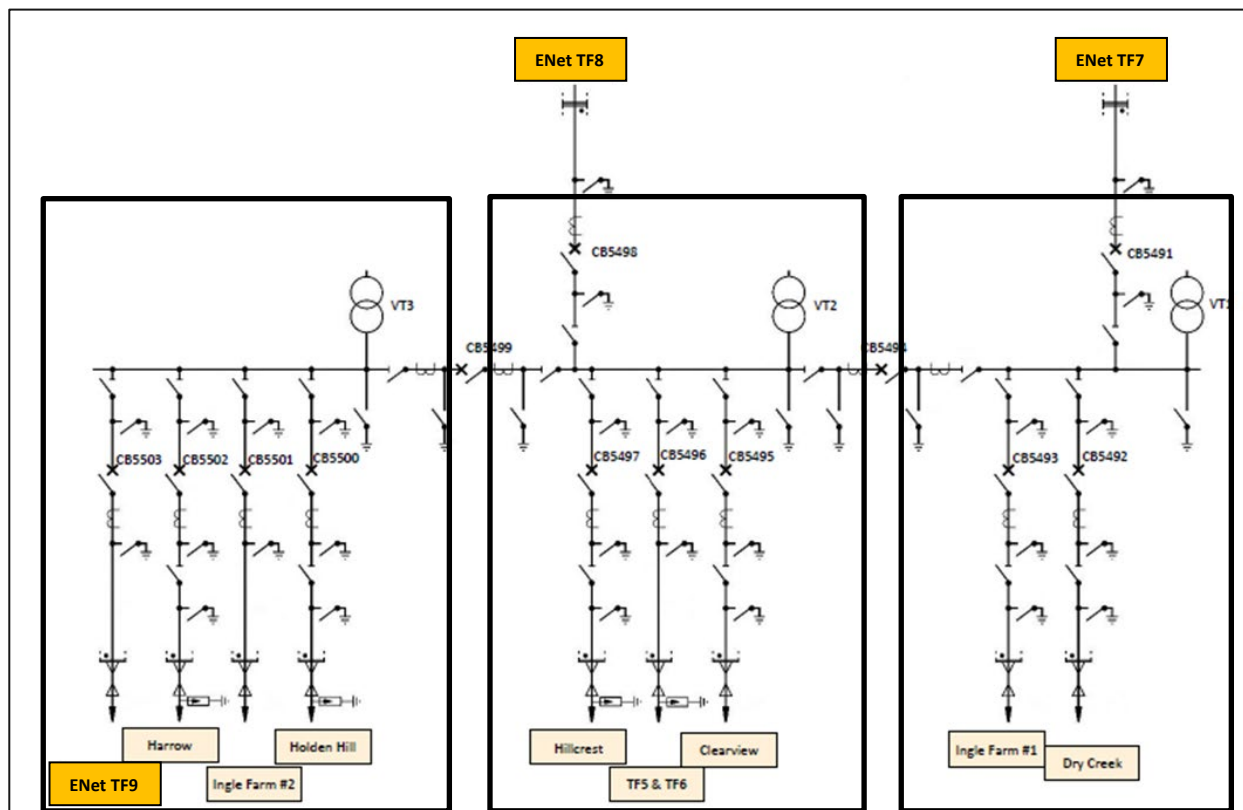


Figure 3 below shows the 66kV GIS at the Northfield substation and a corresponding simplified single line diagram is shown in Figure 4.

Figure 3: Present 66kV GIS configuration



Figure 4: 66kV GIS configuration

The switchboard high voltages (HV) are insulated through the use of a gas, namely sulphur hexafluoride gas (SF_6). This gas is used extensively in the industry as an insulator and an arc interruption medium in gas insulated switchboards, cubicles, circuit breakers and other switchgear components.

Within the switchboard, flanges are used to connect separate sections of switchgear with O-ring seals to contain SF_6 gas within separate chambers. The separate chambers have gas injection ports to enable the chambers to be filled with gas or for topping up should gas leaks occur. The SF_6 gas is critical for the functioning of the electrical equipment and if low pressure occurs, Supervisory Control and Data Acquisition (SCADA) alarms are raised. If a sudden loss of gas was to occur, the circuit breakers will isolate the faulted section.

The failure of a circuit breaker between switchgear sections could disable two thirds of the GIS. Even if the third section remains serviceable, with a replacement build time of at least two years, a second leak could render the entire GIS unserviceable. Alternatively, three independent leaks across the three sections within a two-year period could also render the entire GIS unserviceable. Isolation of a leak is limited to one third of the GIS, or in the case of a section circuit breaker as above, two thirds.

The switchgear at Northfield is considered second generation GIS by manufacturers. While the switchgear at Northfield was designed for outdoor operations, and having over 30 years of continuous service, it is now apparent that the equipment is not well-suited for outdoor operations as is the experience of many other utilities internationally. The issues stem from corrosion and moisture ingress into the flange areas causing the seals between flanges to fail.

A critical element of the design is the rubber gas seal which holds the gas within the chambers. The particular equipment at Northfield was designed with one sealing O-ring instead of two between flanges which other manufacturers adopted at the time and is currently design practice for GIS. The double seal is superior to a single seal due to two key reasons, being:

- it provides higher protection against leaks; and
- if leaks do occur, the repairs are more likely to be successful.

O-ring seals also age over time becoming more brittle. The rate of ageing increases with higher operating temperatures, which, given the outdoor installation of the switchgear, would be made worse.

Deteriorating Condition of the Northfield 66kV GIS

The Northfield 66kV GIS equipment is now showing extensive signs of corrosion throughout the entire asset. In particular, the flange and sealing O-rings are prone to corrosion which has led to SF₆ gas leaks at the site.

In April 2017, there were seal failures at two flanges which resulted in uncontrolled atmospheric SF₆ gas leaks. In September 2019 seal failure occurred on a third flange. The leaks were caused by increasing corrosion on the flange surface, and further leaks are expected which will compromise the integrity of the switchgear. There is also a risk that the growth of corrosion on the flange fixings within the cast resin barrier board flange holes could cause cracking, which is likely to increase the risk of failure of the switchgear. As this switchgear contains over 200 sealed flange joints (i.e. 400 flanges), there is a risk that each are in a similar condition to the failed seals. SA Power Networks considers that further seal failures are likely, with the duration between failures also likely to decrease. That is, further seal failures are likely, and are likely to occur more frequently than presently.

In 2017, SA Power Networks engaged GHD to undertake a study³ to assess the condition and the expected remaining life of the switchgear. GHD found:

- The flanges were in poor condition and several were in a very poor condition due to general water ingress and significant corrosion present.
- The prevention and mitigation of corrosion is critical to ensuring the remaining life of the switchgear.
- Timely sealing of the flanges to prevent moisture ingress, as well as addressing gas leaks, could allow the switchgear to operate for at least a further ten years.
- The consequence of the unavailability of the whole Northfield GIS (albeit rare) would be a critical event with continued inability to supply the load from other network sources until a new substation is constructed and commissioned, with a high impact to its customers.

GHD recommended that SA Power Networks engage in a prudent risk management strategy, adopting a staged approach to building replacement switchgear, and to monitor the future gas leaks which would trigger the timing for the full replacement of the substation. At the time of the report, the breakeven point for the complete replacement was a trend of five to six gas leaks per annum. GHD also recommended that SA Power Networks consider actions to limit the consequence of a critical failure event.

In 2017, GHD considered that a visual external assessment would not be a good indicator of the localised severity of corrosion approaching sealing surface which may subsequently cause a leak. This was because the design of the substation makes it extremely difficult and costly to disassemble flanges for an inspection of the seal area to assess the potential direct impacts from corrosion.

Not being able to undertake an internal inspection means that the internal condition of the GIS switchgear is unknown. There is a risk that if the corrosion is sufficiently severe to penetrate one of the internal GIS chambers, failure of the switchgear would occur through moisture ingress, resulting in an uncontrolled atmospheric release of SF₆ and the switchboard section would be rendered inoperable.

Remedial Repairs and Ongoing Assessment

Following GHD's advice, SA Power Networks included immediate action to address the SF₆ leaks and moisture ingress resulting from severe external corrosion, by refurbishing/repairing the asset. The attempts to provide sealing to stop the leaks was carried out by the manufacturer in October 2018 which aimed to prolong the asset's useful life to allow:

³ SAPN-IR055-Q1-GHD-Northfield 66kV GIS Condition Assessment Final Report-20190626-PUBLIC

- a RIT-D process to be undertaken (planned in 2020); and
- a network/non-network solution to be implement as a result of the RIT-D process within the 2020-25 regulatory control period.

The repair works for one of the leaks at one of the metal-to-metal flanges⁴ was successful. The repair works for the second gas leak at a metal-to-board-to-metal flange took two attempts to seal the leak. However, in January 2019, a gas leak appeared at the same joint which required the manufacturer's experts to undertake further remediation in April 2019 (refer to Supporting Document 5.6.2 - Vendor Report on Northfield 66kV GIS Replacement, Revised Proposal (confidential)). This third attempt failed to stop the gas leak.

The metal-to-board-to-metal flange⁵ repair has been unsuccessful and more severe leakage of SF₆ has occurred compared to the original gas leak. An additional gas leak at another (third) flange was identified in September 2019.

As at July 2019, the manufacturer advised that it is unable to provide the same repair solution as it was no longer viable and alternate options were investigated.⁶ The manufacturer has offered a more invasive method of repair and SA Power Networks is currently evaluating the proposal. However, the very high costs and the extremely high risks associated with the approach may cause risk of:

- Further or other damages to the infrastructure.
- Exposure to supply outages.
- Higher repair costs than currently incurred.

Hence, this alternative repair solution does not reflect a prudent or cost-effective solution.

With the manufacturer unable to supply an economically prudent repair solution for a metal-barrier board-metal joint, other alternative repair solutions are presently being investigated by SA Power Networks. No further information is available at this time given the very early nature of the investigations. Furthermore, as the Northfield GIS is amongst the oldest outdoor GIS installations in Australia, there is relatively little industry experience to draw upon.

Given the multiple failed repair attempts, and the difficulty of finding a successful and economically prudent repair solution, it is likely that SA Power Networks may not be possible to extend the life of the asset to 2030 as original planned however this decision can be made closer to this time.

Through regular routine maintenance and inspections, and SCADA condition monitoring, SA Power Networks continue to assess the condition of the GIS. From GHD's 2017 assessment that visual assessment of the exterior of the GIS is a poor indicator of its condition, no further formal assessments have been conducted.

Figure 5 and Figure 6 show the required SF₆ top-ups at Northfield GIS over the 2013 to 2019 period, and the top-ups and repairs at the Northfield GIS site.

⁴ Metal-to-metal flanges separate sections of the switchboard within sections of one gas chamber

⁵ Metal-to-board-to-metal flanges separate two chambers which can separately be filled or emptied of SF₆ gas

⁶ Supporting Document, 5.6.2 - Vendor Report on Northfield 66kV GIS Replacement (confidential), Page 3 Item 5

Figure 5 SF₆ required to top up losses at Northfield GIS⁷

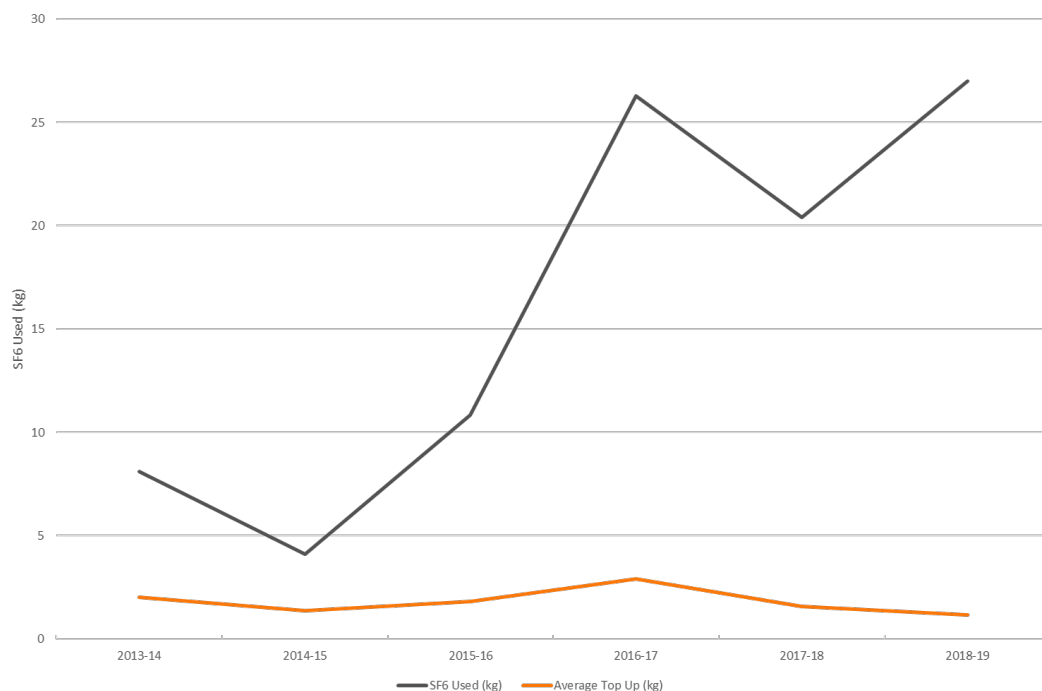
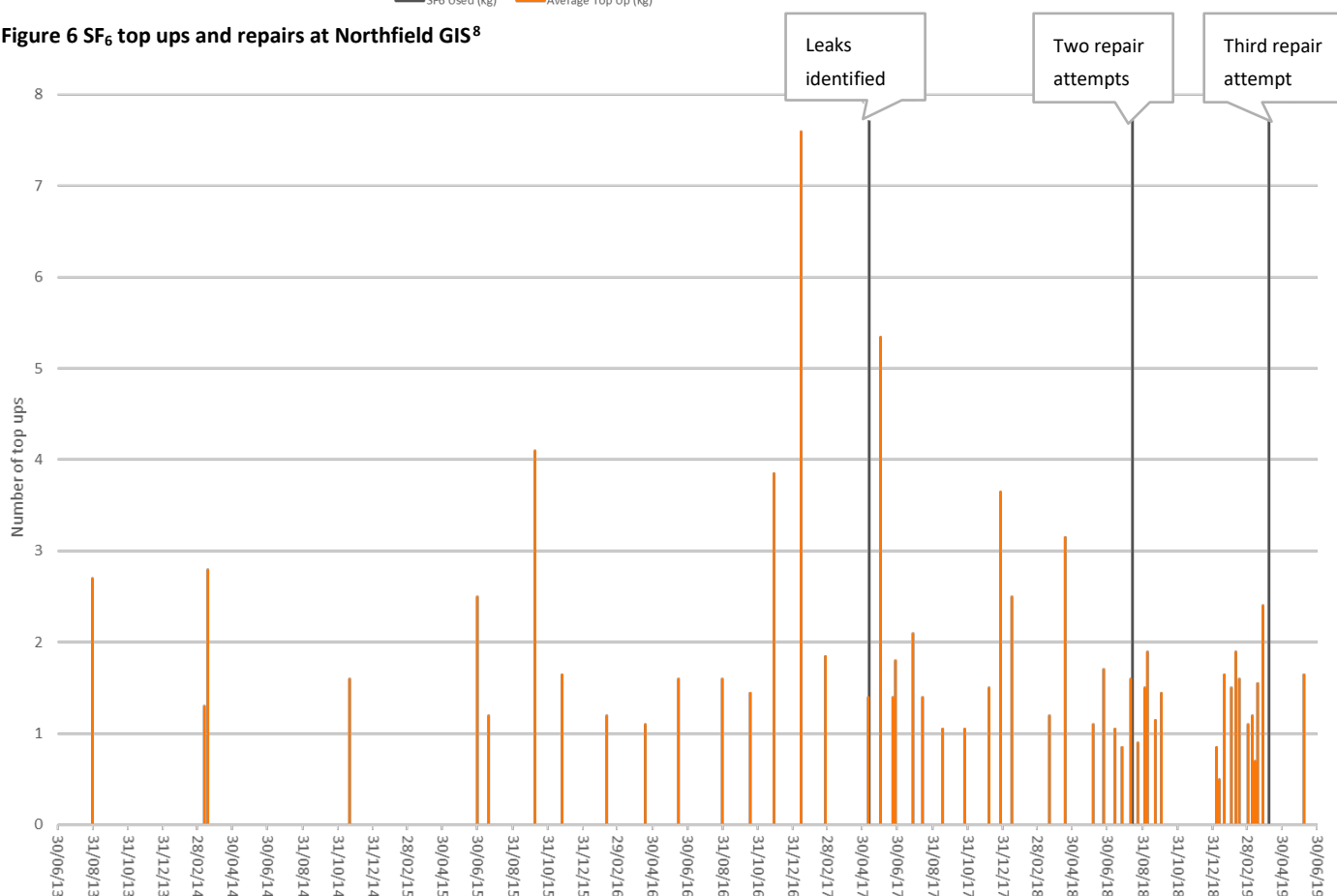


Figure 6 SF₆ top ups and repairs at Northfield GIS⁸



As SF₆ is a hazardous gas, the remedial actions require outages of the switchgear and careful planning by experienced and trained staff following defined handling procedures. The combination of the ageing mechanical componentry, deteriorating physical condition, substantial third party/external repair costs and

⁷ SA Power Networks SF₆ data

⁸ SA Power Networks SF₆ data

extensive down time along with encountering safety issues while undertaking equipment repair result in high costs, reliability, safety and environmental risks.

Failure Event Scenarios and Consequences

In assessing event scenarios two significant failure scenarios were considered, namely:

- Scenario 1: an event where a single GIS bus section failed, and
- Scenario 2: an event where a failure causes two GIS bus sections to be inoperable, such as the failure of the circuit breaker connecting two adjacent GIS bus sections.

In both events, it was assumed the failed GIS was non-repairable and could not be returned to service, triggering replacement. The risks, in terms of likelihood and consequences, were assessed against SA Power Networks' Corporate Risk Assessment model.

Under the first failure scenario, SA Power Networks has contingency response plans in place to re-establish supply from the substation within a 24-hour period. The likelihood of this type of event will be higher than the complete loss of the 66kV GIS (scenario two) but the consequence is much less severe. N demand can always be met, though there is a significant system security N-1 risk which has not been modelled in detail.

Under the second failure scenario, the consequence of a simultaneous failure of multiple bus sections of the switchboard has been assessed as 'Major' under the SA Power Networks Corporate Risk Assessment model, as the critical and continuous loss of supply to the Eastern Suburbs areas supplied by the 66kV network supplied by this substation is at risk.

The most significant consequence of two or more sections of the Northfield GIS failing is the loss of capacity to supply customers at peak times during the summer periods. The second biggest consequence is the initial load lost. The inability to supply peak summer loads may occur through either:

- a sudden unplanned outage/trip; or
- a condition-based failure (such as when the leak rate is too high to top-up and the GIS must be switched out); or
- leaks in the remaining section of the switchgear.

These risks will exist over the next two years while the partial replacement of the substation is undertaken and will not be mitigated if this partial replacement is deferred. Such a failure is as a "Critical" event according to SA Power Networks' Risk Management Framework. The event would extend over a two-year timeframe – reflecting the construction and commissioning timeframe for a new site and substation to mitigate the need for rotating load shedding for all customers on the network.

On this basis, SA Power Networks has undertaken consequence analysis on the forecast loss of supply confirmed through load-flow analysis based on the scenario where two GIS bus sections are rendered inoperable.

The Northfield 66kV GIS Substation supplies 108,000 customers. It has a peak 66kV load of 321MW and an average 66kV load of 96MW. In the event of the GIS switchgear being rendered inoperable, the following consequences are associated with supplying peak load:

- N Risk⁹: 48.5MW (or 16,000 customers) for 15 hours/year
- N-1 Risk¹⁰: 175MW (or 59,000 customers) for 1,236 hours/year (approximately 52 days)

⁹ N Risk refers to the loss of supply due to the first contingent event (loss of GIS switchgear at Northfield)

¹⁰ N-1 Risk refers to loss of supply due to a second coincident event on the 66kV network

The load summary above assumes temporary arrangements can be made within approximately one day to restore some additional capacity.

Considering the N Risk

Under N conditions, the limitations of the 66kV network are the thermal operating limits of feeder conductors to provide the load from alternate sources. The initial action plan by SA Power Networks is to:

- restore supply to the radial substations fed from Northfield (short-term response); and
- construct a temporary feed to the Dry Creek line from one of the other lines (longer term response).

The supply outages would be worse than detailed above without these initial actions. Typically, the unmitigated loss of supply would be spread out over approximately eight days in the year. That is, between 6pm and 8pm on the hottest summer evenings in January and February. As the Eastern Suburbs is predominantly residential, this translates to approximately 16,000 households without supply for approximately eight evenings on the hottest days of the year.

N Risk Assumptions

- Restoration times for initial radial load lost:
 - Harrow, Clearview Substations: 6 hours
 - Northfield 11kV Substation: 8 hours
- Supply constraints:
 - Magill supply: 140MVA
 - Temporary feed from Dry Creek: 137MVA
 - Unserved peak load: 48.5MW (or 16,000 customers)
- The initial outage will occur at a time outside of peak load. That is, the Magill infeed will maintain supply to all customers not radially supplied from Northfield initially, and the temporary infeed from Dry Creek can be built before it's required to serve peak load. If the initial outage occurs at a time of peak load, all 108,000 customers would be lost with the Magill infeed unable to meet demand, and a further 50,000 customers on top of the 16,000 customers would be without supply until the Dry Creek infeed is built in approximately 1 day. Neither consequence was considered due to the difficulty in determining the likelihood in timing of failure compared with demand, but both would increase the risk.

Considering the N-1 Risk

The radial supply network supplied in the N Risk configuration is then vulnerable to second and high probability failure events during hot summer conditions (the network operating at thermal limits). The N-1 risk would be 175MW for 59,000 customers for 1,236 hours/year (approximately 52 days). A second failure on the network in this scenario would be fixed as soon as possible, however, tens of thousands of customers would be impacted by outage.

Customer impacts

Unlike unplanned outages, the load shedding outages that would occur for 2 years while a replacement is built for the failed GIS would predictably fall on hot summer evenings. This is predictable as it's when peak demand and thus a shortfall in capacity occurs. This loss of supply on hot summer evenings will have a varying impact on different age groups within the customer base in the Eastern Suburbs. Elderly people are more likely to develop a heat-related illness during summer than other age groups, due to their age and

higher likelihood to have pre-existing medical conditions.¹¹ Hence, it is widely accepted that elderly persons are considered vulnerable customers for reliability considerations during peak summer periods. Thus, the power outages that are likely to occur in the peak of summer in the event of a failure at the Northfield Substation are likely to impact a higher number of SA Power Networks' customer base that are vulnerable to heat-related illness.

Based on the historical population information published by the Australian Bureau of Statistics for the Adelaide Central Region, there has been a significant increase in the number of customers who are aged over 65 years over the ten-year period to 2018. The compound annual growth rate (CAGR) for persons aged over 65 years was more than 10 times (1.85 per cent) than the customers aged between 40 and 64 years.¹² Hence, the population of the region served by the Northfield Substation is aging, and hence more likely to have a growing proportions of vulnerable consumers.

This is supported by the forecast data shown in Figure 7, as published by the SA Government Department of Planning, Transport and Infrastructure.¹³ Over the period 2016 to 2041, the proportion of persons aged over 70 years is expected to increase, with persons aged over 80 years to more than double. Hence, it is clear that the demographic profile of the Eastern Suburbs will increasingly reflect an older population, meaning that the number of SA Power Networks' customer base that are vulnerable is likely to increase.

¹¹ SA Health (2019) *Stay Healthy in the Heat*, available at:

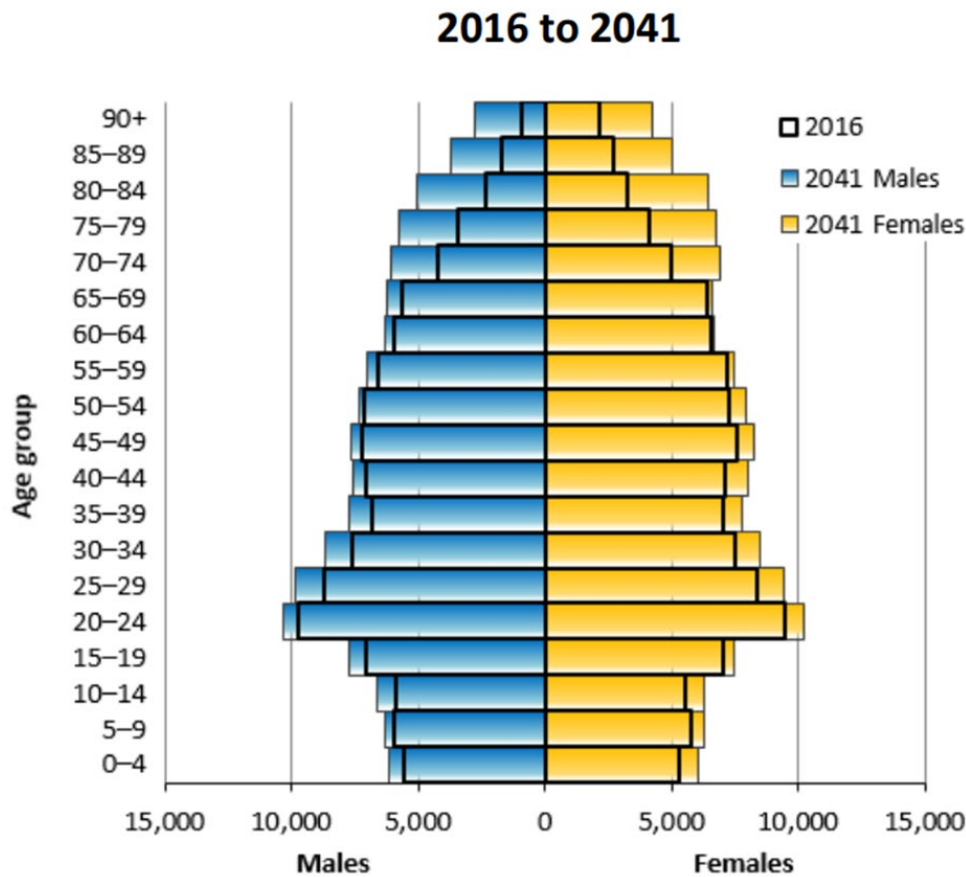
<https://www.sahealth.sa.gov.au/wps/wcm/connect/Public+Content/SA+Health+Internet/Healthy+living/Protecting+your+health/environmental+health/Stay+healthy+in+the+heat/>

¹² Data taken from: 3235.0 Regional Population by Age and Sex, Australia (released 29 August 2019; and 3235.0 Regional Population by Age and Sex, Regions of Australia (released 28 august 2014).

¹³ See page 27 of

https://www.saplanningportal.sa.gov.au/_data/assets/pdf_file/0008/563813/Population_Projections_for_South_Australia_and_Regions_2016-41_-_May_2019.pdf

Figure 7: Demographic profile of Inner Metro Region, 2016 to 2041



Environmental Impacts

The SF₆ leaks from the Northfield Substation are the largest component of reportable greenhouse emissions for SA Power Networks. Figure 8 depicts the quantity of SF₆ emissions over the period 2013-14 to 2017-18.

Figure 8: Aggregate annual weight of SF₆ loss (kg) 2013-14 to 2017-18

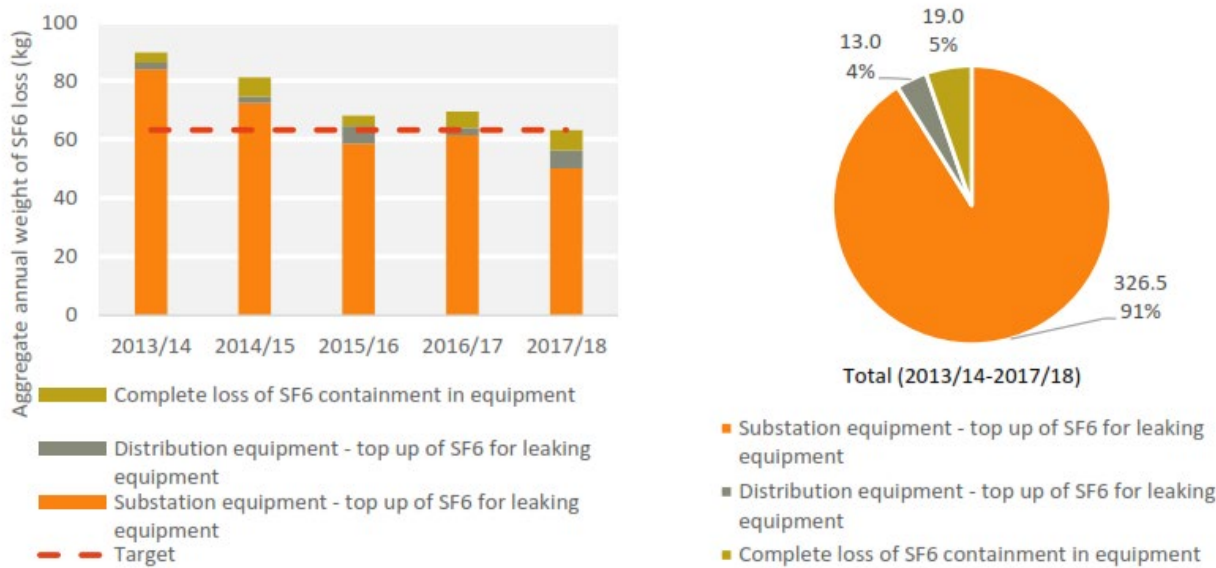


Figure 8 shows that substations contribute the largest emissions of SF₆, which is primarily caused by the common use of SF₆ gas as an insulation and interrupting medium in 33kV and 66kV circuit breakers. The majority of the reportable SF₆ emissions in substations are attributable to the 66kV GIS at the Northfield Substation (approximately 27 kg out of a total of 105 kg in 2018-19).

At present, no penalties exist for greenhouse gas emissions. There's only a reporting requirement to the EPA. The consequences to SA Power Networks for not undertaking works to minimize the SF₆ losses and plan for the replacement of the GIS would be reputational to both SA Power Networks and the broader electricity sector. SA Power Networks may also be at risk of violating section 79 of the *Environmental Protection Act 1993 (SA)*, which states that

*“a person who intentionally, and with the knowledge that environmental harm will or might result, as a result of a polluting activity is guilty of an offence under the [Environmental Protection] Act”.*¹⁴

As SA Power Networks is aware that the failures of the Northfield GIS Substation assets are causing leakages of SF₆, which by all reasonable estimates are expected to worsen without maintenance intervention, it may be construed as intentionally causing environmental harm.

Safety considerations

By comparison, the safety risks are significantly lower compared to the reliability and environmental risks, as the associated safety risks are managed and controlled through existing work practices.

Probability of GIS Failure

A normal distribution curve based on the standard deviation of the square root of the expected design life of the existing GIS has been used to formulate the probability of failure of the existing GIS. The analysis undertaken scales the annual probability of failure rate by assuming no failure prior to 2020. The probability of failure in 2020 is 4.3%, while by 2025 assuming the GIS has yet to fail the cumulative probability of failure will be 35%.

In all four options considered the same probability of failure of the GIS is used in the analysis. This is relevant even to Options 2 and 4 which completely replace the GIS as there's a two-year build window for which the reliability risks of the GIS are still incurred.

¹⁴ Environmental Protection Act 1993 (SA), available at:

<https://www.legislation.sa.gov.au/LZ/C/A/ENVIRONMENT%20PROTECTION%20ACT%201993/CURRENT/1993.76.AUTH.PDF>

Options considered

Non-Network Options considered to be non-credible

Demand side options

Demand side options typically include demand reduction of consumer loads. It takes several years to develop these programs (at least ten years) and would not be feasible for the size of load supplied by the Northfield Substation (321 MW), the relatively high costs and difficulty of reliance on the demand reduction.

Supply side options

The supply side options include:

- Alternative generation supply: the load at risk of the size of 321 MW would not be possible to supply from generation sources that could be mobilised in the event of a failure (approximately the size of a Pelican Point Power Station).
- Development of an emergency injection point: this would involve the construction of a temporary 66kV transformer supply or injection point near the Northfield substation. This would, in effect, represent a duplication of the Northfield Substation. Given the options considered relate to rebuilding of the Northfield Substation, developing an emergency injection point would not be a credible option when compared to the credible options assessed by SA Power Networks.
- Refurbishment of existing switchgear: the design of the switchgear makes it extremely difficult and expensive to undertake the necessary refurbishment work that would be required. This is compounded by shortage of outage windows available to undertake the work and the high risks involved. SA Power Networks obtained pricing from the OEM for the work which was well in excess of the part of complete replacement options.

Credible options assessed by SA Power Networks

SA Power Networks considered four options to address the reliability, security of supply, service standards and environmental considerations resulting from the deteriorating mechanical condition of the 66kV GIS at the Northfield Substation site, which has led to increasing SF₆ leakages from flange failures.

These options are:

- replace the Northfield GIS 66kV switchgear on failure with no intervention, other than undertaking maintenance activities as and when required to manage the ongoing reliability and environmental risks associated with the deteriorating condition of the 66kV GIS switchgear;
- full replacement of existing GIS with Air Insulated Switchgear (AIS) in 2022;
- partial build and replacement of existing GIS with AIS and defer further expenditure while monitoring the performance of the GIS (Defer expenditure until more information becomes available); and
- full replacement of GIS starting in 2023.

SA Power Networks acknowledges that an option is commercially feasible under clause 5.12.2(a)(2) of the National Electricity Rules (NER) if a reasonable and objective operator, acting rationally, would be prepared to develop or provide the option in isolation of any substitute options. An option is considered technically feasible where there is a high likelihood that it will, when developed, provide the services it is proposed to provide.

Options Evaluation

As the timing of GIS failure is in the future and may not occur within the next RCP, a probability of failure curve was used to assess all options, using a study period of 30 years. All costs incurred maintaining the GIS up to its failure and decommissioning and building and maintaining the

replacement are considered over a 30 year window. This allows all options to be compared, as after 30 years the probability of failure is near 100% and replacement is assumed to have been required.

All costs presented in the following options analysis are the NPV over a 30-year period. That is, they're not the costs incurred over the next RCP alone, given the exact timing of the replacement build accounts for most of the cost.

The NPV tool used in the analysis was vetted for use by the AER for SA Power Network's RIT-D submission to install the Kangaroo Island Submarine Cable, dated December 2016.

A summary of the financial analysis undertaken for the four credible options is provided in Table 1.

Table 1: Summary of the financial option for all options under consideration

Present value of costs, over a <u>30-year</u> evaluation period	VCR (\$M), FY2018 terms	Capital, O&M and Refurbishment costs (\$M), FY2018 terms	Total costs (\$M), FY2018 terms
Option 1: Replace GIS on failure	\$15.316	\$21.174	\$36.491
Option 2: full replacement of GIS with AIS	\$5.635	\$26.440	\$32.075
Option 3: partial rebuild of GIS with AIS, then defer half AIS expenditure	\$5.515	\$23.381	\$28.896
Option 4: full replacement of GIS	\$8.056	\$31.984	\$40.039

Option 1 – Replace GIS on Failure

The first option considered by SA Power Networks is to replace GIS on failure. As the timing of failure is in the future and may not occur within the next RCP, a probability of failure distribution curve was used (as for all options). In 2020 the probability of failure is 4.3%, while by 2025 the probability of failure is 35%.

Until the time of GIS failure, Option 1 will include regular maintenance (through refurbishment or repairs), as and when required, namely:

- sealing gas leaks, as and when required
- re-caulking flanges every five years (nominally), or as and when required, and
- reinstating surface protection treatment on any damaged or faulted areas of the existing GIS.

Given the higher risk of failure, any mitigating actions to the consequence of failure would be reactive and would require the replacement of the entire GIS with an air insulated equivalent (AIS) upon failure. This option has no initial major capital costs but will incur on-going and relatively higher maintenance costs compared to installing newer switchgear especially the high cost of SF₆ gas leak repair interventions.

The advantages of this option include:

- Capex for the substation replacement is deferred beyond that achieved by other options.
- The 'service life' of the existing GIS is maximised.

Disadvantages of this option include:

- Reduced customer service, with the consequence of failure resulting in supply interruptions to thousands of customers on hot summer evenings at N and N-1 conditions.
- The likelihood of failure may be high as the internal condition of the existing GIS cannot be assessed; nor can the effectiveness of the proposed maintenance activities be predicted. That is, the existing GIS may fail earlier than assumed. Recent experience has shown some leaks cannot be repaired prudently.
- There are no reasonable options to mitigate the consequence of rotating power supply interruptions should a failure occur, including mobile bypass transformers and generators.
- Building replacement switchgear is expected to take in excess of two years.
- Ongoing and increasing environmental concerns and costs due to further SF₆ gas leaks from the GIS switchgear.
- Repairs for gas leaks and other less extreme failures of the switchgear rely on the availability of external (overseas) original equipment manufacturer (OEM) expertise and resources to undertake any repair should it be possible. Delays would be a major factor in determining if its replacement should be brought forward rather than attempting the repair.

The estimated risk adjusted capital costs for SA Power Networks to implement this replacement is \$21.2 million (excluding land purchase). This replacement cost is factored into the NPV evaluation as a probability of failure in a particular year times the replacement cost. The estimated NPC of the risk to VCR for Option 1 is \$15.3 million.

SA Power Networks anticipates that this option will incur the capital and operating costs detailed in Table 2.

Table 2: Summary of present value of risk-adjusted costs in a 30-year period associated with replacing the Northfield GIS 66kV switchgear on failure

	Cost item	NPV of costs (\$M) FY2018 terms
Direct costs	Capital costs	\$15.130
	Operations and maintenance costs	\$5.250
	Refurbishment costs (non-invasive)	\$0.795
Total costs		\$21.174

Option 2 – Full replacement of existing GIS with AIS from 2023

This second option involves the complete and immediate replacement of the existing 66kV GIS with an equivalent infrastructure using AIS on a vacant parcel of land at the southern end of the existing substation. The 66kV line arrangements beyond Northfield Substation would remain unchanged in this option.

The proposed intervention option for the immediate replacement of the 66kV GIS includes:

- Creation of a new three bus section 66kV installation at Northfield Substation using AIS.
- Connection of the output of three existing 275/66kV ElectraNet transformers to the AIS.
- Transfer of all existing 66kV line exits from the substation to the new AIS installation (seven in total).
- Transfer of the existing 66kV supply to SA Power Network's 66/11kV transformers also at Northfield Substation to the new AIS installation.
- Installation and commission of all protection, control and telecommunications infrastructure associated with the AIS installation, both at Northfield and remote-end substations.
- Decommissioning and removal of the existing 66kV GIS installation.

Advantages of this option include:

- Improved customer service, as this option eliminates the need for rotating power supply interruptions on hot summer evenings to thousands of customers.
- The risk of failure and loss of supply events is significantly reduced compared to Option 1.
- The impact of failure of the GIS is completely removed compared to Option 3.
- The AIS installation is effectively a modular system in which faulted components can be removed/replaced individually.
- The AIS installation is made up of standard AIS components which SA Power Networks already uses and has 'in-house' expertise and skills necessary to install/maintain/test the components.
- The use of AIS eliminates the need for SF₆, eliminating the gas leaks and related environmental management and reporting issues associated with the existing GIS.

Disadvantages of this option include:

- The total initial capital cost is higher than that incurred for the replacement of the substation compared with Option 3.
- ElectraNet is required to invest capex to implement wider technical solutions for connection to the new substation earlier compared to Option 3.
- Potential impact on any other work required in the distribution network while the network is in an abnormal configuration.
- The existing GIS does not achieve the initial expected service life of 40 years.

Construction would commence in 2022 and take an estimated three years to complete (covering the design, build and commissioning phases). The option assumes the short-term interventions would still take place so that the existing GIS can remain in a serviceable condition until this option can be completed in 2025.

The estimated cost for SA Power Networks to implement this option is \$26.4 million (excluding land purchase). The estimated NPC of the risk to VCR for Option 2 is \$5.6 million. SA Power Networks anticipates that this option will incur the capital and operating costs (NPC) detailed in Table 3 to meet the identified need.

Table 3: Summary of present value of risk-adjusted costs in a 30-year period associated with full replacement of GIS to AIS from 2023

	Cost item	NPV of costs (\$M) FY2018 terms
Direct costs	Capital costs	\$19.543
	Operations and maintenance costs	\$6.898
	Refurbishment costs (non-invasive)	\$-
Total costs		\$26.440

Option 3 – Partial build with AIS in 2023, and defer full replacement

Option 3 involves the replacement of the existing GIS with AIS over two stages instead of Option 2 which is in one stage. The first stage would be undertaken in 2023 and Stage 2 would be deferred until the condition and performance of the GIS requires it to be replaced. It is estimated that Stage 1 would take 24 months to complete and Stage 2 would take a further 24 months to complete at a later time, when the remaining existing GIS fails. Exactly when the GIS fails and thus stage 2 is required is unknown. The probability curve indicates a cumulative failure rate of 35% by 2025, 70% by 2030 and 91% by 2035.

Option 3 assumes that short-term interventions would continue on the existing GIS to ensure it can remain in service until at least Stage 1 is complete and to defer Stage 2 for as long as practical.

The proposed intervention option for the partial build with AIS includes:

- Establishing the minimum infrastructure necessary to enable for a timely response to a contingency event.
- Civil works, earth grid, site security and a control building for the site.
- Installation of the complete 66kV AIS bus
- Installation of two 66kV feeder exit to feed into the 66kV network.
- Installation of a 66kV underground cable supply via ElectraNet’s transformer (TF9) connecting to the new 66kV AIS bus.

The staged approach to replacing GIS with AIS would mitigate the consequences of failure of the existing GIS and allow for faster restoration, improving network reliability. The staged approach proposed in Option 3 is also consistent with best practice risk management methods, better preparing SA Power Networks for an extreme event with high consequences occurring.

The purpose of the partial build is to reduce the consequences of the existing GIS failing after Stage 1 is completed. The partial build would also permit the supply restoration process to SA Power Networks’ customers to be fast-tracked, giving increased confidence to customers that the restored network would be reliable and further loss of supply could be avoided.

Advantages of this option include:

- Improved customer service, as this option eliminates the need for rotating power supply interruptions on hot summer evenings to thousands of customers.
- Over half of the expenditure can be deferred, resulting in a lower initial cost than Option 2 to implement.
- Allows SA Power Networks to choose the optimal timing for Stage 2 to be undertaken, based on existing GIS performance, condition and risk.
- The AIS installation comprises standard AIS components which SA Power Networks already uses and has ‘in-house’ expertise and skills necessary to install/maintain/test the components.

Disadvantages of this option include:

- Maintenance costs will continue to be incurred on the existing GIS until it is finally removed from service at the end of Stage 2.
- The assets installed in Stage 1 would incur maintenance costs until after Stage 2 is completed.
- The likelihood of GIS failure remains unchanged as the internal condition of the existing GIS cannot be assessed; nor can the effectiveness of the proposed maintenance activities be predicted which means the existing GIS may still fail before Stage 2 of this option can be completed.
- The environmental management, reporting issues and other impacts associated with SF₆ gas leaks are not eliminated until the equipment is replaced in Stage 2.

The estimated cost for SAPN to implement this option will be over two stages:

- Stage 1: \$11.7 million for the initial AIS substation construction (excluding land purchase).
- Stage 2: \$13.0 million to complete the AIS substation and decommission and dismantle the current GIS switchgear at some time into the future. This replacement cost is factored into the NPV evaluation as a probability of failure in a given year multiplied by the replacement cost.
- An additional \$0.8 million is for refurbishment of the existing GIS, common to options 1-3.

The estimated NPC of the risk to VCR for Option 3 is \$5.5 million. SA Power Networks anticipates that this option will incur the capital and operating costs (NPC) detailed in Table 4 to meet the identified need.

Table 4: Summary of present value of risk-adjusted costs in a 30-year period associated with partial build in 2023, then defer expenditure

	Cost item	NPV of costs (\$M) FY2018 terms
Direct costs	Capital costs	\$16.727
	Operations and maintenance costs	\$5.860
	Refurbishment costs (non-invasive)	\$0.795
Total costs		\$23.381

Option 4 - Full replacement with GIS starting in 2023

This option is similar to Option 2 in that it involves the complete and immediate replacement of the existing 66kV GIS at Northfield Substation but in this option, the existing outdoor GIS would be replaced with another GIS system. To avoid a repeat of the corrosion issues experienced by the existing GIS, the new GIS would be an indoor version, housed within its own dedicated building.

GIS is generally more suitable for situations where the available land and real estate is too small for an AIS substation or too expensive such as within CBD areas. In the case of the replacement for Northfield there is available land currently owned by ElectraNet where sufficient land can be made available for a lower cost AIS substation.

Other disadvantages include:

- The full initial capital cost incurred by SA Power Networks since there is no option available for deferral of some of the costs as compared with Option 3.
- When compared to an equivalent AIS solution (Option 2), this option is approximately 30 per cent more expensive in initial capital outlay.
- An indoor GIS requires the establishment of a dedicated building to house it in, adding to the cost of the installation and incurring on-going costs to maintain the building.
- Some immediate solutions are required to be resolved with ElectraNet relating to technical solutions for the supply of 66kV from the two GIS connected 275/66 kV transformers.
- The continued use of GIS equipment means that SA Power Networks must continue to retain 'in-house' expertise to maintain or repair the specialized switchgear.
- GIS is highly specialised equipment and any purchase will involve very long delivery times, making it a 'critical path' item within the construction program.

- SF₆ GIS (including up to 66kV) may become a non-preferred type of switchgear from an environmental/greenhouse impact perspective in the future, with potential future legislative changes and alternatives being developed by manufacturers.

The estimated cost for SA Power Networks to implement this option is \$32.0 million (excluding land purchase). The estimated NPC of the risk to VCR for Option 4 is \$8.1 million. SA Power Networks anticipates that this option will incur the capital and operating costs (NPC) detailed in Table 5 to meet the identified need.

Table 5: Summary of present value of risk-adjusted costs in a 30-year period associated with full replacement of existing GIS with new GIS, from 2023

	Cost item	NPV of costs (\$M) FY2018 terms
Direct costs	Capital costs	\$23.664
	Operations and maintenance costs	\$8.340
	Refurbishment costs (non-invasive)	\$-
Total costs		\$31.984

Recommended option

Consistent with the Australian Energy Regulator's (AER's) RIT-D Guidelines,¹⁵ SA Power Networks ranked each credible option based on each option's present value of costs for the sum of the value of customer reliability (VCR) and capital, operating & maintenance (O&M) costs. This analysis indicated that Option 3: partial replacement with AIS in 2023 and deferring the remainder of the capex until full GIS failure was the preferred option. Option 3 is associated with the lowest risk to the VCR and has the second lowest total capital, operating and maintenance (O&M) costs.

Deferring the completed replacement (Option 1) is associated with the lowest capital cost, in present value terms. However, deferring the expenditure results in a significant risk to the security and reliability of power supply in the Eastern suburbs of Adelaide. It also results in ongoing and increasing environmental concerns as a result of further SF₆ gas leakages caused from failures in the GIS switchgear. In addition, repair works on faulted sections of the switchgear become more complex and at great risk, as they rely on the availability of external (and international) OEM expertise and resources to undertake any necessary repair work, with very high cost and long recall times should complications arise.

Option 3 (partial rebuild of GIS and defer the remaining expenditure) presents the lowest risk to VCR while Option 1 reflects the highest risk to VCR. The risk to VCR between Option 2 and Option 3 is minimal, however, the benefit of Option 3 over Option 2 is that a significant portion of the expenditure under Option 2 is deferred, which results in cost savings for customers. Option 3 provides further benefits through improved customer service by eliminating the need for rotating power supply interruptions during the peak of summer for thousands of households in the Eastern Suburbs region. It also enables SA Power Networks to optimise the timing of the Stage 2 works, meaning that it can apply best-practice asset management

¹⁵ Australian Energy Regulator (2018) *Application guidelines: regulatory investment test for distribution*, December 2018

techniques to ensure the most efficient outcome in terms of cost are achieved, while retaining supply reliability for customers. When the VCR is added to the total capital costs, Option 3 is the least-cost option.

Table 6: Ranking of each credible option, \$M, FY2018 terms

Present value of costs, over a 30-year evaluation period	VCR (\$M), FY2018 terms	Capital, O&M and Refurbishment costs (\$M), FY2018 terms	Total costs (\$M), FY2018 terms	Ranking
Option 1: Replace GIS on failure	\$15.316	\$21.174	\$36.491	3
Option 2: full replacement of GIS with AIS	\$5.635	\$26.440	\$32.075	2
Option 3: partial rebuild of GIS with AIS, then defer half AIS expenditure	\$5.515	\$23.381	\$28.896	1
Option 4: full replacement of GIS	\$8.056	\$31.984	\$40.039	4

On this basis, SA Power Networks considers Option 3 to be the best solution. It has the second lowest risk-adjusted direct capital costs in FY2018 present value terms. It is associated with the least risk of a loss of supply event (VCR) and is thus considered to be the most economically viable solution. The net benefit of this option compared to the base case (Option1) is \$7.595M (\$36.491M less \$28.896M). It also provides an appropriate technical solution which addresses the identified need.

Estimated costs

Assumptions and limitations

1. All present value costs are based on a pre-tax real WACC (discount rate) of 2.63 per cent.
2. To escalate the costs to FY2020 terms, SA Power Networks applied:
 - CPI (All groups CPI; Australia; A2325846C), as published by the Australian Bureau of Statistics, for June 2017 (110.7) and June 2019 (114.8). This is the CPI series that SA Power Networks has used in its revenue proposals.¹⁶
 - An assumption that the June 2019 CPI will grow by 1.75 per cent in June 2020, based on the Reserve Bank of Australia's Statement of Monetary Policy's forecast (November 2019).¹⁷
3. The capex presented reflects the absolute direct capital costs, in nominal FY2018 and present value terms.
4. The environmental costs associated with the leakages of SF₆ have not been factored into the analysis. This is compliant with section 3.5.2 of the RIT-D Guidelines.

¹⁶ Refer: <https://www.aer.gov.au/system/files/SA%20Power%20Networks%20Pricing%20Proposal%202018%20v2.2F.pdf>

¹⁷ See Table 5.1

CAPEX

The estimated capital cost to implement Option 3 is \$13.1 million over the 2020-25 RCP (in FY2020 terms), as shown in the table below and the explanatory notes that follow.

CAPEX Option 3 (\$M, inc. all overheads)

Work package	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Totals (\$2018 inc. overheads)	\$2.5	\$6.0	\$4.0	\$0.0	\$0.0	\$12.5
Totals (\$2020 inc. overheads)	\$2.6	\$6.3	\$4.2	\$0.0	\$0.0	\$13.1

Notes:

1. The \$13.1 million estimate includes capitalised refurbishment of the existing GIS (referred to as short-term interventions and ongoing maintenance for flanges and leaks in the *Northfield GIS Investment Strategy*).

To consider the CAPEX for Option 1 in the 2020-25 RCP requires an assumption on the timing of the GIS failure which will initiate the replacement build incurring most of the capex. Assuming GIS failure occurs after the 2020-25 RCP;

CAPEX Option 1 assuming GIS failure post 2025 (\$M, inc. all overheads)

Work package	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Totals (\$2020 inc. all overheads)	\$0.1	\$0.1	\$0.2	\$0.4	\$-	\$0.8

Similarly, to consider the CAPEX for Options 1 and 3 beyond the 2020-25 RCP also requires an assumption on the timing of the GIS failure. Disregarding depreciation and the value of money, the CAPEX is the same with a \$1M difference for staging Option 3. However, the reliability benefits (VCR) of Option 3 are not realised in Option 1. Assuming failure occurs within the 2030-35 RCP (when the probability exceeds 90%);

CAPEX Option 1 & 3 assuming GIS failure 2025-30 RCP (\$M, inc. all overheads)

Work package	2020-25	2025-30	2030-35	Total
Option 1 (\$2020 inc. all overheads)	\$0.8	\$0.8	\$26.6	\$28.3
Option 3 (\$2020 inc. all overheads)	\$13.5	\$0.8	15.0	\$29.4

Estimated benefits

As shown in the table below, relative to the base case (Option 1), Option 3 has an estimated positive net benefit of \$7.595 million (NPV to 2047, FY2018 terms), applying a WACC of 2.63%.

NPV relative to base case (\$M, \$2018)

Item	NPV to 2047
Cost of preferred option (capex + opex)	\$2.207
Value of Customer Reliability	\$9.802
Net outcome	\$7.595

Comparison of options

Cost/benefit analysis

Of the options considered, Option 3 provides the highest net market benefit in NPV terms (\$7.60 M, FY2018) relative to the base case (Option 1). Option 2 was next best (\$4.42M, FY2018), while Option 4 yielded a worse outcome (-\$3.55M, FY2018) than the base case.

Net Market Benefit compared with Option 1 (\$M, \$2018)

Option number	NPV to 2047
Option 2: complete replacement of GIS to AIS	\$4.415
Option 3: partial rebuild and defer expenditure	\$7.595
Option 4: full replacement with GIS	(\$3.549)

Sensitivity analysis

In constructing the sensitivity cases, our approach has been:

- to focus on credible future scenarios;
- to explore changes in those input variables most likely to affect the performance of credible options; and
- to consider variables most likely to affect the ranking of net economic benefits across the options under consideration.

To test the options against a range of plausible future scenarios, the cost/benefit modelling was repeated for the following sensitivity cases:

- Discount rate
- Value of Customer Reliability (VCR)

- Capital Cost
- GIS Failure Rate
- Cost of Gas Leak Repairs

Discount Rate

Table 7 shows that if the discount rate (pre-tax) increases from a base 2.63 per cent to 6.63 per cent, Option 3 remains the preferred option. The same outcome is observed when the discount rate is decreased to 0.5 per cent. Varying the discount rate by 4% is in line with industry best practice.

Table 7: Sensitivity analysis on the discount rate, NPC, \$M

Option / Discount Rate	2.63% (Base Case)	6.63% (Upper bound)	0.5% (Lower bound)
Option 1: defer expenditure	\$36.491M	\$40.793M	\$28.411M
Option 2: complete replacement of GIS to AIS	\$32.075M	\$32.840M	\$28.206M
Option 3: partial rebuild and defer expenditure	\$28.896M	\$30.217M	\$24.568M
Option 4: full replacement with GIS	\$40.039M	\$41.203M	\$34.966M

Value of Customer Reliability (VCR)

Table 8 shows the testing of the net present cost of VCR over three different scenarios (Low: \$26,663/MWh, Base Case: \$38,090/MWh and High: \$49,517/MWh). Option 3 remains the preferred option varying the VCR by 30% (above industry best practice of +/-15%), and with VCR expected to rise by a corresponding amount shortly Option 3 is more favored over 1.

Table 8: Sensitivity analysis on the value of customer reliability, NPC, \$M

Option / VCR	\$38,090/MWh (Base Case)	\$26,663/MWh	\$49,517/MWh
Option 1: defer expenditure	\$36.491M	\$31.870M	\$41.038M
Option 2: complete replacement of GIS to AIS	\$32.075M	\$30.376M	\$33.748M
Option 3: partial rebuild and defer expenditure	\$28.896M	\$27.233M	\$30.534M
Option 4: full replacement with GIS	\$40.039M	\$37.609M	\$42.431M

Capital Costs

Table 9 shows the sensitivity analysis performed on the capital costs, in present value terms. SA Power Networks applied three scenarios to the capital costs, being Low: 80%, Base Case: 100% and High: 120%, which is in line or above industry best practice of +/-10%. Option 3 remains the preferred option over the range of values.

Table 9: Sensitivity analysis on the capital costs, NPC, \$M

Option / Proportion of capital costs	100%	80%	120%
Option 1: defer expenditure	\$36.491M	\$33.428M	\$39.480M
Option 2: complete replacement of GIS to AIS	\$32.075M	\$28.153M	\$35.971M
Option 3: partial rebuild and defer expenditure	\$28.896M	\$25.538M	\$32.228M
Option 4: full replacement with GIS	\$40.039M	\$35.292M	\$44.749M

GIS Failure Rate

Table 10 details the sensitivity analysis performed on the failure rates of the GIS switchgear. Three scenarios were analysed relating to the onset of increased probability of failure measured by the age when the cumulative probability of failure (Pof) reaches 5% per annum. The three scenarios assessed were 32, 37 and 42 years of age. The 32-year scenario is the base case representing Northfield switchgear near to reaching its end of effective operating life and 42 years representing the life of GIS switchgear installed indoors and not affected by corrosion and the risk of early failure.

Table 10: Sensitivity analysis on GIS failure rate, NPC, \$M

Option / failure rate	32 years Cum. Pof of 5% (Base Case)	37 years Cum. Pof of 5%	42 years Cum. Pof of 5%
Option 1	\$36.491M	\$26.436M	\$19.445M
Option 2	\$32.075M	\$26.703M	\$25.808M
Option 3	\$28.896M	\$22.682M	\$19.985M
Option 4	\$40.039M	\$32.555M	\$31.254M

In line with expectations, delaying the expected failure distribution for the switchgear to 37 years significantly reduces Option 1. All other options also reduce, but at a lesser rate. Option 3 remains the superior option. Delaying the expected failure distribution for the switchgear to 42 years illustrates the point where continuing to run the Northfield GIS switchgear would equate to the same position as the preferred option (Option 3). Based on probability of failure the sensitivity analysis

confirms Option 3 as the preferred option given the known condition of the switchgear, the current O-ring seal failures and gas leaks.

Cost of Gas Leak Repairs

As Option 3 remains the preferred option until the cumulative PoF exceeds 42 years. Repairing gas leak by the manufacture costs SA Power Networks around \$200,000 per repair in total. The sensitivity analysis shown in Table 11, demonstrates that Option 2 - Full replacement of existing GIS with AIS from 2023 become the preferred option which is consistent with the findings by GHD which was based on a higher WACC value.

Table 11: Sensitivity analysis on cost of gas leaks, NPC terms, \$M

Option / failure rate	42 years Cumulative Pof of 5% 0.5 gas leaks per annum	42 years Cumulative Pof of 5% 3 gas leaks per annum
Option 1	\$19.445M	\$25.228M
Option 2	\$25.808M	\$25.808M
Option 3	\$19.985M	\$25.768M
Option 4	\$31.254M	\$31.254M

Non-quantified benefits

Safety and environmental risks in comparison to reliability risks are much lower, benefiting by the fact that no penalties currently exist for greenhouse gas emissions and safety risks are managed and controlled through existing work practices. The consequences currently related to SF₆ losses and greenhouse emissions would be reputational risk to SA Power Network (and the wider electricity industry) should not action be taken by SA Power Networks to minimise the losses and to plan for the replacement of the switchgear as soon as possible to eliminate the emissions.

Alignment with our asset management objectives

Option 3 (Partial build in 2023, then defer expenditure) is most consistent with SA Power Networks' capex objectives of maintaining the safety, reliability and security of the distribution system.¹⁸ In particular, Option 3 best meets the requirements of SA Power Networks' replacement and refurbishment asset management strategies, including the accompanying scope of works selected for this asset category, being appropriate to meet the capex objectives.

Option 3 (Partial build in 2023, then defer expenditure) also aligns with SA Power Networks' asset management objectives for circuit breakers, which are outlined in Table 12. In particular, it is consistent with *safety* and *reliability and resilience*. Additionally, the replacement of the existing equipment in stage 2 will align with the asset management objectives for *Environment*.

Table 12 Asset management objectives for circuit breakers¹⁹

Level of service category	Asset management objectives
Safety	<ul style="list-style-type: none"> • No injuries/deaths to staff or contractors through installing, operating, inspecting, maintaining/repairing, replacing or decommissioning circuit breakers. • No circuit breaker condition or functional failures resulting in injury/death. • No instances of circuit breakers failing to operate when required.
Reliability and resilience	<ul style="list-style-type: none"> • Minimise planned and unplanned interruption frequency and duration from circuit breaker failures and replacements. • Minimise long term (10-year) equipment major failure rates.
Environment	<ul style="list-style-type: none"> • Minimise the oil loss from circuit breakers entering the environment. • Minimise the volume of SF₆ gas from circuit breakers entering the environment. • Minimise the potential environmental damage from fire or catastrophic switchboard failures.
Communication and information	<ul style="list-style-type: none"> • Provide accurate information on restoration times for unplanned outages. • Provide accurate advanced notice of any planned circuit breaker works involving outages.
Efficiency	<ul style="list-style-type: none"> • Minimise circuit breaker life-cycle costs including the cost of installation, operations, maintenance, refurbishment/replacement and disposal. • Continual improvement of circuit breaker CBRM models for life-cycle decision making.

¹⁸ See page 36 of <https://www.aer.gov.au/system/files/SAPN%20-%20Attachment%205%20-%20Capital%20expenditure%20-%20January%202019.pdf>

¹⁹ SA Power Networks, Power Asset Management Plan – Manual No. 16

Conclusions

Based on the financial analysis undertaken by SA Power Networks, the recommended option is Option 3. It has the second lowest direct capital and operating costs of \$23.381 million, in present value terms and the lowest risk to VCR of \$5.515 million, in present value terms. Hence, Option 3 with the greatest Net Market Benefit is considered to be the most commercially viable solution. It also provides a technically viable solution which addresses the identified need.

This recommended option includes stage building an AIS replacement to mitigate the reliability risk of rotating power supply interruptions on hot summer evenings to thousands of customers. It also defers over half the capex of a full replacement. In the 2020-25 regulatory control period, the total cost is \$12.5M including all overheads. Sensitivity analysis shows that Option 3 remains the preferred option over a reasonable range of changes in input variables.