

RESILIENCE AND RELIABILITY FOR ELECTRICITY NETWORKS

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Abstract: Electricity networks in Australia operate in a highly regulated framework. This framework monitors network investment to ensure positive benefits for customers and includes incentivised performance standards that cover reliability. In the current standards, major event days are excluded from the statistics for outages, because they are deemed to be outside the control of the network operators. Outages on major event days are typically the result of severe weather and tend to be prolonged and have a significant negative impact on customers, but current regulations do not cover such events.

The ability of any system to be ready for and recover from a major event is described as resilience, but resilience is not an incentivised activity for electricity networks and the impact of climate change means that major event days are increasing in number, leading to higher costs for customers.

Without a regulatory focus on resilience, a network may meet or exceed reliability standards, while still not being resilient in major events. Investing in reliability does not always deliver resilience, but investing in resilience is demonstrated to deliver significant improvements in both resilience and reliability, resulting in beneficial performance outcomes for customers using cost-effective and efficient network investment approaches.

Keywords: Resilience, electricity, networks, severe weather, reliability

NATURAL HAZARDS

Australia can be characterised as the land of natural hazards, largely weather-related. In addition, the types of events and their impact are highly dependent on climate variability, such as the Southern Oscillation Index (El Nino/La Nina), with cyclones and flooding more prevalent in the La Nina phase and droughts and bushfires more common in the El Nino phase. Australia's most expensive extreme weather events tend to occur in La Nina years as a result of cyclones and storms (Figure 1).

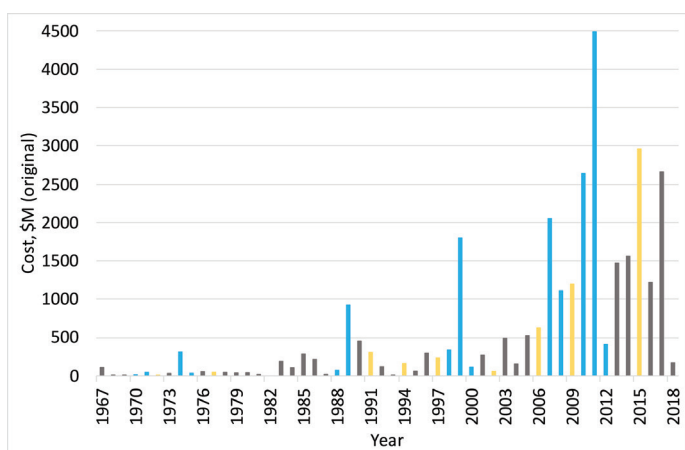


Figure 1: Insured cost of severe events (Insurance Council of Australia 2018).

An assessment of the number of deaths (Table 1) for a given natural hazard demonstrates the impact of extreme heat, which has the most severe impact on life of all the natural hazards in Australia. The issue of extreme heat

and bushfires is of particular significance to the electricity networks.

Table 1: Number of deaths related to Natural Hazards in Australia, 1844–2011 (Coates et al. 2014).

Natural hazard	Deaths 1900–2011	% of total deaths
Extreme heat	4,555	55
Flood	1,221	15
Tropical cyclone	1,285	16
Bush/grassfire	866	10
Lightning	85	1
Landslide	88	1
Wind storm	68	1
Tornado	42	1
Hail storm	16	0
Earthquake	16	0
Rain storm	14	0

RELIABILITY

Australia's electricity networks are a significant part of critical infrastructure, providing lifeline services to customers both big and small. Because of the critical nature of the services supported by electricity, the Network Service Providers (NSPs) are required to meet performance standards, including standards that cover delivering a reliable supply of electricity. The Service Target Performance Incentive Standards (STPIS) are administered by the Australian Energy Regulator (AER

2018) and focus on two aspects of electricity outages: the duration of outages and the frequency of outages. The two critical industry metrics monitored are the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). SAIDI is the average duration of outages for each customer served by that network, while SAIFI determines the average frequency (how often an outage occurs) of outages for each customer served by a named network.

Both SAIDI and SAIFI (Figure 2) have shown improvements over the last twelve years. Between 2006 and 2017 the average length a customer was without power has been reduced by 39 minutes, from 146 minutes (2 hours, 26 minutes) to 107 minutes (1 hour, 47 minutes), although reductions in duration stalled in the period 2013–2016 (118 minutes). Over the same period, SAIFI has improved from 1.77 outages per customer to 1.10 outages per customer.

However, SAIDI and SAIFI are determined on a specific subset of performance data, which ensures the focus is only on ‘normal’ days of operation. Days where there is unusually bad weather, including fire weather, are excluded from performance monitoring. So, when a Major Event Day (MED) occurs, any outages from that day can be ignored. This may seem entirely reasonable because it ensures that networks are assessed fairly, and that performance data aren’t skewed by an atypical or ‘rare’ event. But it also means that the responsibility for delivering resilient networks that can ride through MEDs is ignored.

WEATHER AND NETWORKS

Natural hazards affect electricity networks in a number of ways. Weather represents over half of all electricity outages (Figure 3) and is often the cause of prolonged outages that have an impact on significant numbers of customers.

Strong winds may directly bring down overhead lines and poles, but fallen trees and tree debris also represent a significant source of damage to overhead lines. Falling trees may lift up underground cables (Figure 4). Flooding may inundate substations and underground assets, rendering them unusable (Figure 5). Earthquakes have an impact on both overhead and underground assets, but they are particularly damaging for underground cables, which are costly and time-consuming to repair/replace.

Fire weather, characterised by strong gusty winds, low humidity and high temperatures, results in bushfires, another natural hazard that has a major effect on electricity networks (Figure 6). Bushfires not only burn through above-ground network assets, but electricity networks are potentially a source of ignition for bushfires, particularly on extreme fire weather days (Miller et al. 2017).

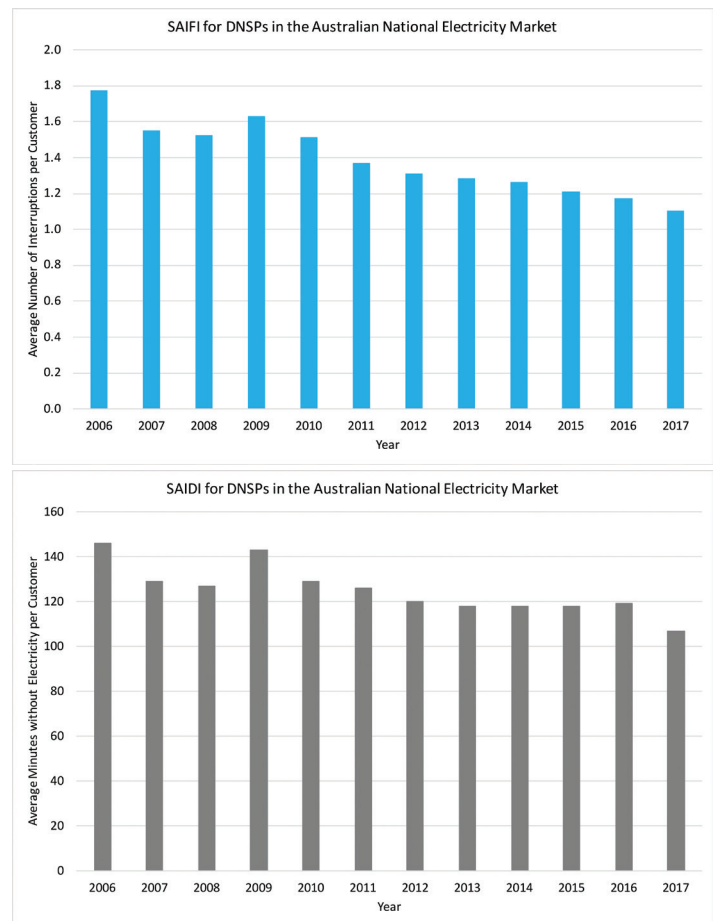


Figure 2: SAIDI and SAIFI data for Australian DNSPs (excluding Western Australia; AER 2018).

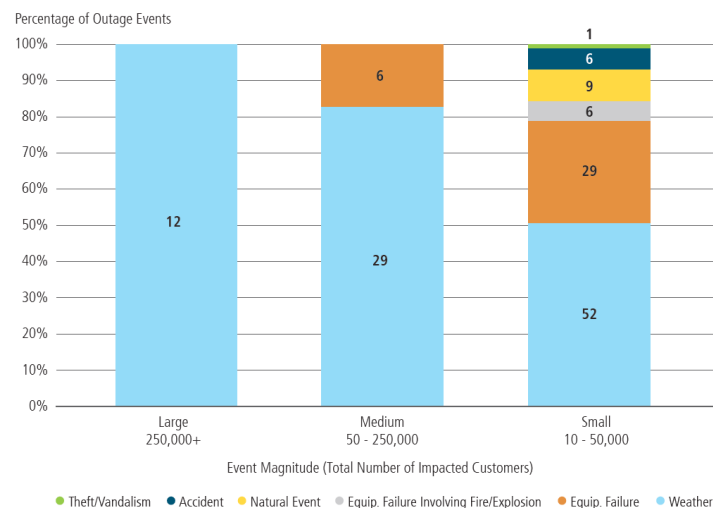


Figure 3: Role of weather in outages by cause and magnitude (DOE 2017).

BUSHFIRES AND EXTREME HEAT

The costs and impacts of bushfires are increasing, and fires are becoming harder to manage as communities expand beyond the urban fringe and into bush. Not only does this place property in an environment where fire is a significant risk, but it also means that network infrastructure supporting properties requiring power is built in treed environments.



Figure 4: Uprooted tree damaging electricity network equipment (Credit: Nycshooter/E+/Getty Images).



Figure 5: Flooded power poles (Credit: secablue/E+/Getty Images).



Figure 6: Bushfire encroaching on transmission towers (Credit: GomezDavid/iStock / Getty Images Plus/ Getty Images).

Electricity networks are both impacted by and one of the potential causes of bushfires.

Broadly, there are two types of network fires: those caused by an asset failure and those caused by a contact event. In Victoria, where there is a regulated scheme to monitor network fires, asset failures represent over 57% of fire starts, with contact events representing 43% of network fires. Fifty per cent of network asset fires in Victoria escape electricity equipment and become ground fires, with prevailing environmental conditions (weather and fuel condition) determining whether the ground fire becomes a major bushfire (ESV 2018).

The failure of assets is something that the network can manage and, following Black Saturday (February 2009), the utilities in Victoria have undertaken significant work to reduce the potential for fires on their electricity networks, thereby substantially reducing the risk of electricity assets igniting a bushfire.

Trees represent a real threat to electricity infrastructure and managing them is complicated, difficult and expensive. Trees and their debris not only represent an ignition risk by bringing down lines, but they also result in a significant number of outages during less severe storms. Even when trees are cleared or trimmed back away from poles and wires to maintain a clearance zone, branches may still snap off and become mobile in strong winds. Predicting which

trees will fail and at what wind speed is challenging, and often networks have no control over what tree is planted where.

In California, another location with a significant bushfire risk, the state's investor-owned utilities spend close to a total of AUD\$350 million per year on maintaining regulated clearance zones around distribution powerlines. Clearing or trimming trees can cause friction between the utility and their customers (Malashenko 2018).

One approach to completely removing the risk posed by an electricity network of starting a fire is to preemptively de-energise those parts of the network at high risk of starting a fire on extreme fire weather days. This is not an option yet used in Victoria but is an option allowable in South Australia and in other parts of the world. De-energisation is an option used by some utilities in the USA and it demonstrably reduces the risk of and prevents electricity infrastructure being the source of a bushfire. This is because any damage that does occur to the network during fire weather due to high winds and debris, does not result in arcs. However, de-energising a network is a 'last resort' approach, which utilities do not take lightly because it leaves customers without power for extended periods (CPUC 2018).

Extreme fire weather days are characterised by strong gusty winds and high temperatures. The weather event that prevailed during Black Saturday was also an extreme heat event. And while 173 people lost their lives to bushfires, 389 people died as a result of exposure to high temperatures. As shown in Table 1, extreme heat is Australia's most significant natural killer (Nicholls 2019). Medical research shows that those with a working air conditioner at home are 77% more likely to survive an extreme heat event than households without (Broome & Smith 2012), and no electricity means no air conditioner.

No electricity, perhaps as the result of preemptive de-energisation or a fault, affects customers. This is particularly true in rural areas, which tend to be at higher risk of bushfire, because rural properties often rely on a water pump to deliver water from dams and tanks, so no electricity means no water either for drinking (customers and livestock) or fighting fires. No electricity also means no communications once batteries have lost charge. This is an issue for individual customer devices and the wider communications network (e.g. mobile towers) that are needed by not only customers, but by the emergency services. Communications are essential for customers to understand the location of a bushfire and the need to evacuate. Communications are also essential for electricity networks to monitor and understand how their networks are functioning.

One common approach to improving reliability has implications for managing the bushfire risk posed by damaged networks. Automatic reclosers are one approach to improving reliability, as over 80% of overhead line faults are transient, that is, a branch contacting lines results in a fault, but that branch then falls to the ground. A standard fuse would operate and then require a line-crew to search out the operated fuse and replace it, resulting in a long outage for customers. A recloser operates (opens) and then after a pre-determined delay it closes. If the fault has resolved (e.g. branch falls to the ground), power is restored.

However, in the case of a permanent fault on a high-fire-danger day, and without changes to the protection settings to reduce reclose attempts to zero, the recloser is opening and closing on to the fault, creating sparks at the fault that may ignite a bushfire. Electricity networks typically set reclosers to open and not attempt to reclose at the start of and for the duration of the fire season, essentially acting like a standard fuse. But this means every single fault on a line is permanent, requiring the attendance of a crew and a long outage. And most networks have a movement ban on high fire danger days to keep their crews safe, meaning that customers could be without power for very extended periods.

There are technical approaches electricity networks can take to reduce the arcs and sparks on their network,

including 'spark-less' fuses, ground fault neutralisers, and novel automatic reclosers that use less energy to test for a fault, minimising the risk that a downed conductor will ignite a fire. Some of these technologies have the benefit of not only reducing bushfire risk but also improving everyday reliability and delivering resilience.

IMPACT OF CLIMATE CHANGE

Bushfire risk is increasing due to climate change, with research indicating that the Forest Fire Danger Index (FFDI) in Australia will more than double by 2050, and the fire season is now longer than it was in the 1970s (BoM & CSIRO 2016). This means that managing the fire risk posed by operating an electricity network on an extreme fire weather day is becoming more challenging and new approaches are needed.

As the climate continues to change, there is likely to be an increased number of storms, leading to an increased number of MEDs. The number of natural hazard events is increasing with time, with fewer years with no or a single event (Latham et al. 2010). Events are not just more numerous, but they are increasingly costly in insurance terms (Latham et al. 2010). Cyclone Debbie (March–April 2017) represents the world's tenth costliest natural disaster at US\$2.7 billion. If MEDs are ignored in performance standards, then it is not possible to incentivise the deployment of approaches that will lead to more resilient networks.

RESILIENCE

It is not just reliability that is a concern. It would be prohibitively expensive to build networks that are 100% reliable, and so a balance must be reached. A key focus is how rapidly a network can recover from an MED. This is 'resilience': the ability to rapidly recover from a major incident by reconnecting as many customers as quickly as possible and minimising the time without power.

It is important to consider the subtle difference between reliability and resilience. Reliability is focused on the average network performance and seeks to minimise outage time during normal conditions as well as unplanned outages. Techniques around this traditionally have focused on proactively replacing assets before they reach end of life and fail.

Resilience looks specifically at the 'bad days' and a network's ability to withstand them. Rather than avoiding the effect of MEDs, it focuses on these days and measures the ability to both withstand and recover from major events. This inherently implies that resilience will in effect increase reliability, but the reverse is not true; a network could dramatically increase its reliability and that would have little to no effect on its resilience.

Resilience for networks

The Federal Energy Regulatory Commission in the United States has defined resilience as: ‘The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event’ (FERC 2018). This definition considers both what can be done before an event to minimise its impact as well as the response to an event.

The *New Zealand Civil Defence Emergency Management Act* (MCDEM 2002) is in the process of being amended to account for the priorities of the Sendai Framework (2015), in particular Priority 3, which has relevance to critical infrastructure, such as electricity networks: ‘Investing in disaster risk reduction for resilience’. In New Zealand, the 2002 Act bases resilience on the ‘4Rs’:

- Reduction: take preventative steps to avoid or mitigate adverse consequences
- Readiness: risk management is comprehensive and integrated; developed capabilities, well practiced; educate and communicate with the public
- Response: liaise with lead agency and activate plan; assess consequences, maintain and restore services, communicate and plan recovery
- Recovery: escalation is minimised, regeneration and enhancement is realised; future risks reduced.

The specific requirements of the 2002 Act, as they apply to electricity utilities, were supported with further policy advice (September 2017) encouraging utilities to identify ‘prudent resilience measures’ to pursue through price–quality regulations. The New Zealand regulator, the Commerce Commission, will be assessing current regulations around investment to ensure that the regulated investment framework delivers resilient infrastructure.

Be prepared

Typically, governments and critical infrastructure providers focus on responding to an incident after it has occurred, trying to manage the event and its aftermath. International agencies (e.g. UNISDR, Sendai Framework) encourage an approach that supports risk reduction and preparedness. There is evidence to show (NIBS 2017) that every dollar spent reducing risk prior to an event replaces the four dollars that would need to be spent on recovery and response.

Cost-benefit analyses are difficult for risk-reduction measures because the cost of mitigating risk is assessed against the cost of an event that subsequently either didn’t occur or the impacts of that future event were reduced. Cyclone Debbie (March 2017) cost more than AUD\$1.71 billion in recovery and repairs and had a major impact

on Australia’s economy (ICA 2018). However, the cost savings of risk reduction versus event management could be significant using the 1:4 ratio (NIBS 2017).

Case study

Automation is an important tool that distribution networks can use to improve their recovery time from an outage. Automating a network allows power to be restored to as many healthy sections of the feeders as possible before a field crew even has time to drive out to address the fault. Automation will limit the extent of an outage to the size of the faulty section and not have an impact on the full feeder. In the aftermath of a severe event, automation can manage a significant number of outages, restoring power without the intervention of crews, while leaving those crews to target the more serious problems where equipment and lines need to be repaired or replaced.

Southeastern United States of America is exposed to hurricanes, which result in flooding, storm surge and high winds. Most outages are the result of fallen trees and wind-blown debris. Following a number of severe storms, including Hurricane Wilma in 2005, a local utility began a program of ‘grid hardening’ in preparation for a future major event.

The utility manages a network with 850 km of coastline, high salt loading resulting in high corrosion, fast vegetation growth, high keraunic (i.e. lightning) activity, and a susceptibility to hurricanes. Storm preparedness covered short-term activities immediately before a forecast hurricane and longer-term activities, such as investing in assets.

Long-term approaches to improve resilience included strengthening poles and protecting substations from flooding. A significant program of tree management was undertaken to reduce the impact of trees on powerlines, but trimming trees can be contentious with customers or protected due to conservation. While undergrounding equipment would intuitively suggest protection from severe weather, strong winds will uproot trees, bringing underground equipment and cables to the surface. Automatic reclosers were also deployed widely within the network, allowing faults to be cleared automatically without the attendance of crews, and shortening restoration times. Data show that everyday reliability improved by more than 30% (FPSC 2018).

The utility also had a meteorologist on staff to provide expert advice on approaching weather systems and to help support planning the response effort. The utility also worked closely with community and local groups to provide support to customers and to determine priority connections for restoration.

Immediately before Hurricane Irma (2017), the utility

deployed crews into the forecast impact zone, ensuring that those local crews and interstate workers were safe. Being in position ensured reduced response times after the centre of the storm passed. The settings on automatic reclosers were modified (extended) on the basis of assessments made in a less-severe storm, which revealed relationships between gust behaviour and the clearing of debris from powerlines (Gwaltney 2018).

The combination of long-term investment in assets and tree management, plus the specific planning for Hurricane Irma, allowed the utility to significantly reduce reconnection times for the majority of customers in comparison with the response to Hurricane Wilma, which was a less-severe storm, over ten years earlier.

All substations were returned to service within one day of the passage of Hurricane Irma, and while Irma

affected 90% of the utility's customers, restoration times were shorter, with the average customer outage reducing by nearly 60% (Table 2).

Delivering resilience

As the definitions for resilience from the USA and NZ and the case study demonstrate, methods for delivering resilience can be split into activities either prior to or in response to an event or outage.

Preparation before and readiness to respond after an event are both critical for delivering resilience, and only a few of the approaches described in Table 3 have been discussed here. Planning and practice are also key, with utilities in NZ and USA running live simulations with communities and governments to test preparedness on an annual basis.

Table 2: Comparison of Hurricanes Wilma and Irma: Impact and Recovery (Gwaltney 2018).

	Hurricane Wilma (2005)	Hurricane Irma (2017)
Saffir-Simpson Scale	Category 3	Category 4
Max wind speed in Florida	190 kph	210 kph
Customers impacted	3.2 million	4.4 million
Hurricane path	Southwest to northeast	South to north
% of customers	75 %	90 %
Poles damaged	12,400	4,600
Substations de-energised	241	92
Time to restore substations	5 days	1 day
Customer Restoration (full)	18 days	10 days
50%	5 days	1 day
75%	8 days	3 days
95%	15 days	7 days
Average customer outage	5.4 days	2.3 days

Table 3: Approaches to electricity network resilience (after Silverstein et al. 2018).

PREPARATION FOR OUTAGE			RESPONSE TO OUTAGE	
Planning	Hardening & Damage Prevention		System Recovery	Survivability
System design	Asset redesign	Physical security	Spare equipment	Back up generation
Asset design	Asset configuration	Grid modernisation	Mutual assistance	Distributed generation
System models	Undergrounding	Transmission automation	Black start	Storage
Threat characterisation	Operations & maintenance	Distribution automation	Damage assessment	Microgrid
Vulnerability assessment	Tree trimming	Advanced meters	Incident management	Energy efficiency
Reliability standards	Situational awareness	Synchrophasors	Outage management system	Distribution management system
Interconnection	Generation fleet diversity	Emergency drills		Graceful failure
	Fuel contracts	Emergency planning		Urgent service
	Cyber security			Demand response
	Secure communications	OUTAGE		

How to incentivise

There are few established metrics to monitor the resilient performance of an electricity network. Because major event days are typically excluded from reliability monitoring and metrics, they should remain outside of current approaches to incentivise reliability and instead be incentivised as a separate resilience activity.

The UK regulator, Ofgem, does incentivise resilience, but the incentives are focused on rapid recovery rather than the capability to withstand major weather events. Under RIIO-1, there are in place severe-weather standards for performance that require the UK utilities to restore supplies within set timescales, depending on the severity of the event (severe weather events are excluded from the main reliability incentive). The compensation under these standards is significant (at the maximum representing more than the average annual electricity cost for each customer affected) thereby providing a strong incentive to the utility.

In some of the Scandinavian countries (Sweden, Finland), there is a focus on resilience following a series of major storms that affected a large proportion of customers. The routine Finnish reliability incentives are unusual in that they do not exclude severe weather events. The *Finnish Electricity Act* requires that service interruptions caused by storms or snowfall must not exceed six hours in urban areas or 36 hours in any other areas.

New standards of performance and incentives should apply for resilience on major event days. One possible metric is the time taken to reconnect customers:

- full reconnection of all customers
- reconnection of 90% of customers ('CR-90')
- reconnection of 75% of customers
- reconnection of 50% of customers.

'CR-90' is a standard used by regulators in some US states to monitor and incentivise recovery after an event.

Resilience metrics could include a comparison of the average customer outage between previous and subsequent events, which is similar to that used by Ofgem, but the issue would then be determining the comparative severity of different events. Ofgem has adopted an approach of categorising events to allow comparison:

- category 1 events that exhibit from 8 to 13 times the daily mean number of faults at higher voltage
- category 2 events that exhibit greater than 13 times the daily mean number of faults at higher voltage
- category 3 events where more than a certain percentage of total distribution customers are affected.

The required restoration is 24 hours for a category 1 event and 48 hours for category 2 event. The restoration time for a category 3 event is based on a formula.

CONCLUSIONS

The number and cost of major events due to natural hazards are increasing. Severe weather and natural hazards have major impacts on electricity networks. Customers are reliant on electricity and having access to power is particularly critical during extreme heat events, when air conditioning can reduce health risks. Electricity is also important in rural areas for pumping water to drink, for livestock and to fight fires. Supporting communications is also important during a major event, when a secure electricity network and the needs of communication networks overlap.

A balance needs to be made to ensure that customers receive both a reliable everyday service and a resilient service at a level that is deemed to be reasonable. There is the possibility that focusing only on reliability will result in increased costs for customers in the face of the increasing impact and cost of repairs related to natural hazards. Investment in risk-reduction approaches for networks not only improves resilience, leading to more rapid recovery, but also improves everyday reliability and represents an efficient use of funds.

Additionally, every dollar spent on risk reduction potentially replaces four dollars that would be spent on recovery and response following a severe event.

Regulated performance standards need to include incentives for risk reduction because this will deliver resilience as well as improved reliability. Incentivising resilience reduces costs for electricity customers and reduces the costs and impacts of a severe event, not only for the affected customers, but for the wider community and the country by reducing the need for post-event funding.

Conflict of interest

The author declares no conflicts of interest.

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