Ausgrid Submission

IPART Reliability Standards Review

May 2020

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15 May 2020

Attn: Brett Everett
Independent Pricing and Regulatory Tribunal
2-24 Rawson Place
Haymarket, NSW 2000

Dear Mr. Everett

Ausgrid welcomes the opportunity to provide this submission on the Independent Pricing and Regulatory Tribunal's (IPART) Issues Paper on the NSW electricity distributor's reliability standards. We also appreciate the consultation that IPART has undertaken with the NSW distribution businesses to date.

Since our reliability standards were last updated, we have made significant steps towards improving both the affordability and reliability of our service. Our annual revenue per customer is now 45% lower than it was in FY2013. At the same time, we have seen improvements to reliability performance. The average duration (SAIDI) of outages on our network is now 5% less than in FY2010 while the frequency (SAIFI) of outages has reduced by 38%.[1]

Energy affordability and maintaining a level of reliability that our customers value, will remain a key focus for Ausgrid over the coming years. The way customers use electricity is nonetheless changing, and we recognise that our reliability standards may need to reflect this.

While once energy flowed in a single direction on our network, it is now increasingly flowing 'two-ways' as customers take up new technologies that enable them to generate, store and send energy back to the grid. Other technologies, such as Stand Alone Power Systems (SAPS) and community batteries, are also presenting opportunities in terms of how networks can more efficiently and reliably provide critical energy network and related services to our customers.

We fully support IPART undertaking a review of how changes in technology and the way customers use energy should be incorporated into our reliability standards. We do, however, wish to raise our concerns about some aspects of the approach IPART outlined in its Issues Paper. These primarily centre around IPART's flagged use of an economic model to develop reliability standards. In summary, we are concerned that:

- **Risk of reintroducing deterministic planning**

  The setting of reliability standards based on the outputs of a single economic model risks creating rigid investment obligations that could be akin to a reintroduction of deterministic

[1] Reliability results adjusted for major event days (MED)

planning. This could happen if the outputs from IPART's economic modelling are deemed a 'jurisdictional obligation' that would bind future regulatory decisions made by the Australian Energy Regulator (AER).

- **Implementation of probabilistic planning at Ausgrid**

  Our investment decisions are based on a probabilistic approach to network planning which considers the probability of unserved energy and cost benefit analysis to determine the optimal investment decision. We are concerned that developing an additional economic model, to be run in parallel with our own economic analysis, would introduce operational inefficiencies and not improve affordability.

- **Consideration of the role of stakeholders in the regulatory process**

  Though economic tools are an important part of the regulatory process, the outputs from a single model are not an adequate or full substitute for the extensive stakeholder consultation which is undertaken to inform network investment decisions, particularly in the lead up to the submission of a regulatory proposal to the AER. Nor can modelling take into account changing customer preferences which we seek to assess through consultation.

- **Our planning approach is in line with best practices for distribution networks**

  We have over 2,300 feeders on our network. Our probabilistic planning approach identifies the risk of unserved energy by considering future network load constraints, reliability performance, and outage recovery strategies. Where we identify risks to reliability, we will then conduct a site-specific investigation. We consider this to be a prudent and efficient approach to making distribution network investment decisions. Thus detailed analysis is done where a specific risk has been identified. In contrast, the approach flagged by IPART, would require detailed analysis across every element of our network.

Our submission is divided into two parts. In Part 1, we provide general comments on matters relating to IPART's review while Part 2 sets out our response to each question in the Issues Paper.

We shared a draft version of this submission with members of our customer consultative committee (CCC). The input we received has then be incorporated into our submission. We started requesting customer advocates to provide feedback on draft versions of submissions last year. It provides valuable input into the policy positions we reach and is helping us on our journey to become a more customer centric organisation.

If you would like to discuss our submission in more detail please contact Shannon Moffitt, Senior Regulatory Analyst, on [redacted] or shannon.moffitt@ausgrid.com.au.

Yours sincerely

[redacted]

Iftekhar Omar
Head of Regulation

Part 1: General comments

Our submission is divided into two parts. Part 1 provides general comments on a number of matters related to IPART's review of our reliability standards. These include:

- Amending the reliability standards: we make recommendations for how IPART could amend the distribution reliability standards to:
    - increase network resilience in the face of more extreme weather events;
    - cater for increasing levels of distributed energy resources (DER); and
    - provide adequate levels of reliability for SAPS customers.
- Affordability: how Ausgrid has taken significant steps to address customer affordability concerns over recent years
- Economic modelling of efficient investment: how Ausgrid's approach to probabilistic investment planning ensures the most efficient level of investment

Detailed responses to each question in the Issues Paper are then contained in Part 2 of this submission.

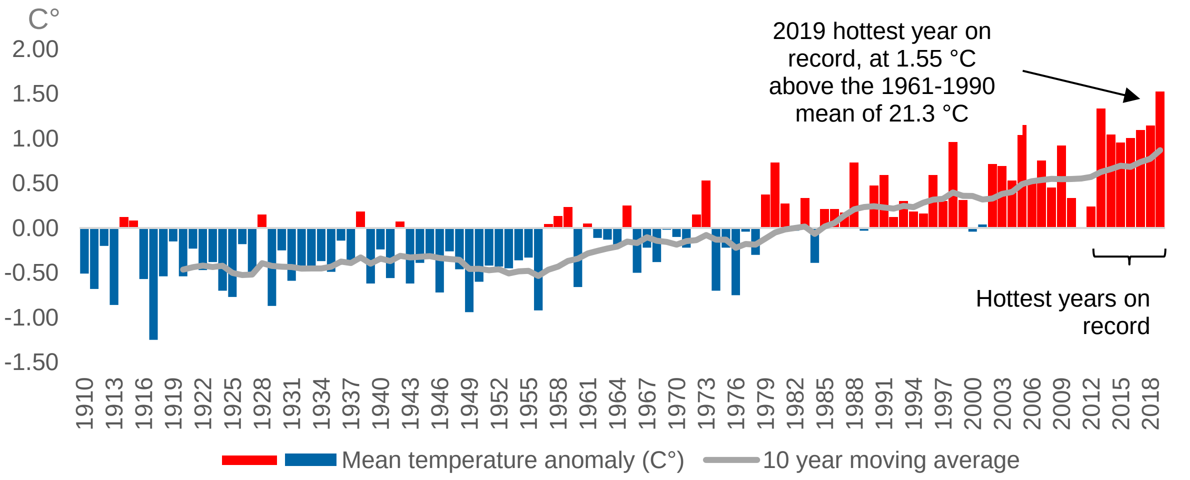
Our recommended focus

In this section, we outline a set of recommendations which we consider IPART should focus its assessment on when reviewing our reliability conditions.

Climate change and network resilience

Australia recently had its warmest year on record. The 2019 national mean temperature was 1.52 °C above average, well above the previous record of +1.33 °C set in 2013. This is part of a broader trend. Figure 1 sets out the variations in Australian mean temperatures relative to the 1961-90 average. It shows that every year since 2013 has been among the ten warmest on record and, out of those ten warmest years, only one (1998) occurred before 2005.

Figure 1 Australian annual mean temperature variations



Source: Bureau of Meteorology: http://www.bom.gov.au/climate/change/#tabs=Tracker

Climate change is exacerbating inherent risks in Australia's climate. Droughts and extreme weather have always occurred but, with a warming planet, they are now increasing in intensity and frequency.

Even in the driest year on record, parts of Australia broke flood records in 2019. In the case of NSW precipitation was among the lowest levels ever, but when it has occurred it has tended to be in an intense downpour or storm event. The figures below illustrate this trend. Figure 2 shows the daily rainfall recorded from the Sydney observatory since July 2019 while Figure 3 plots the maximum wind speed reached at the same weather station from that date. Two storm events, on 6 September 2019 and 26 November 2019, are highlighted along with a February 2020 extreme weather event known as an East Coast Low.

Figure 2 Rainfall in Sydney in 2019 and 2020 to date (mm)

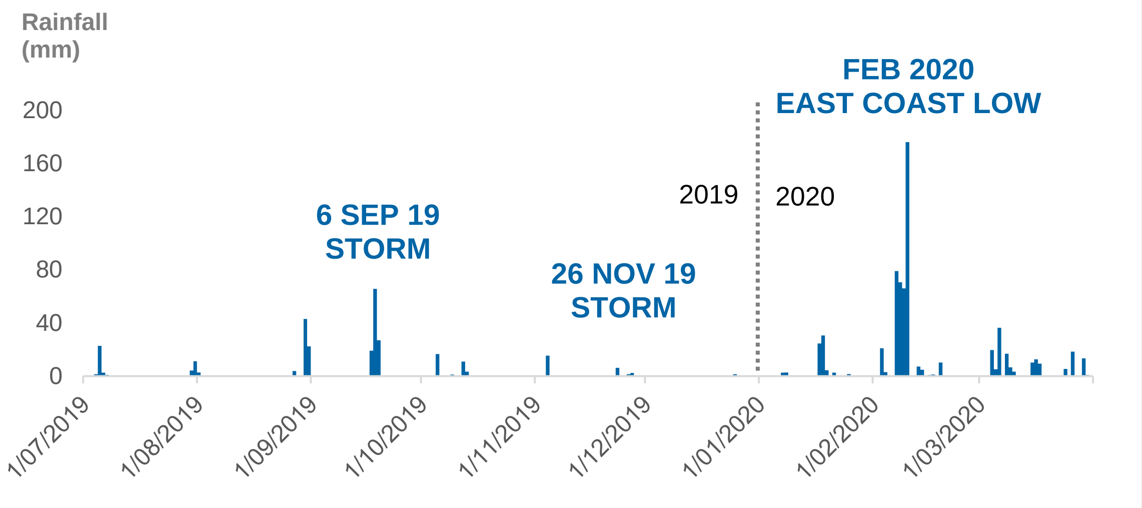
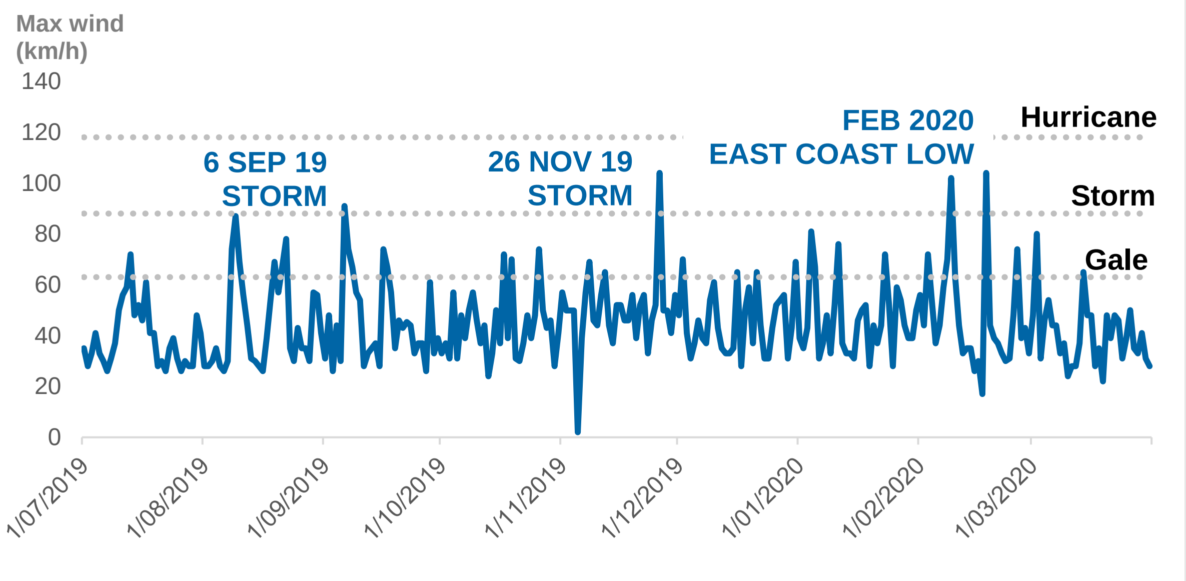


Figure 3 Max wind speed in Sydney in 2019 and 2020 to date (km/h)



Climate change and its impact on bushfire and storm prone areas is the most significant risk to our long-term ability to deliver a safe, reliable and secure energy network service to our customers. IPART's review offers an opportunity to examine the relationship between climate change, network reliability and affordability from a customer's point of view.

To do this, IPART may consider working with the NSW electricity distributors, customer advocates and other regulators to examine the value customers place on network resilience. This could be measured in terms of customer expectations and willingness to pay for networks that can respond to the expected increase in the frequency and severity of extreme weather events. The findings could then be used to inform decisions about whether (or not) to invest in transitioning to a more resilient grid.

We shared a draft version of this submission with customer advocates before lodging it with IPART. In response, the Total Environment Centre (TEC) commented on what 'network resilience' should look like. The TEC stated that rather than seeking to 'strengthen' the grid to withstand more extreme weather events, network resilience should promote the transition to more 'flexible' energy systems capable of adapting to the new reality that climate change presents. The TEC also noted that the cost of acting to improve network resilience should be weighed against inaction – for example, in rural areas a SAPS arrangement may be a more cost-effective alternative to investing in improved network resilience. We believe these are valuable points that warrant further discussion.

Two-way flows and hosting capacity

The original design of Australia's electricity system was based on one-way energy flows, from large-scale centralised generators to customers. As growth in distributed energy resources (DER) has accelerated, this is changing – with energy flows now increasingly becoming 'two-way'.

The take-up of DER and the emergence of two-way energy flows is giving rise to issues in some areas of our network. If these issues are not prudently managed, then a scenario such as in Western Australia could emerge, where Horizon Power placed a temporary moratorium on new DER installations out of concerns relating to grid stability.

Regulatory reform is now needed in two areas. These are:

1. Establishing an agreed Value of Customer Exports (VCE), and
2. Clear recognition of and incentives for the integration of DER.

<u>Agreed value for customer exports</u>

We support the development of a VCE metric that reflects the value customers place on the ability to export energy they have generated or stored using DER technologies.

The need to invest in upgrading hosting capacity is increasing. The cost of installing new DER continues to fall while the enthusiasm to invest in these technologies among customers continues to rise. The deployment of Virtual Power Plants (VPP) also compounds the impact of active energy resources on our distribution network, by clustering and co-ordinating how customer owned DER exports to the grid.

In South Australia, these developments led to SA Power Networks proposing to spend $32 million on a dynamic DER management strategy. Electricity distributors in Victoria have put forward similar proposals relating to hosting capacity and DER integration too.

These developments drive the need to have an agreed value for VCE. It would provide a firmer understanding of the customer willingness to pay for investments that expand hosting capacity. In planning our network, an agreed VCE value would also become an important input into the probabilistic approach we undertake when making investment decisions. This would help ensure that investments in DER integration capabilities are only undertaken when they generate net benefits to customers.

We look forward to working with IPART on this issue and are pleased to see that there is recognition of an emerging need for our Licence Conditions to take into account of two-way energy flows and the integration of DER on our network. In the coming weeks and months, we would like to collaborate with IPART on how its views feed into the Distributed Energy Integration Program (DEIP)[2] Access and Pricing Working Group and any related rule changes that arise from it. We agree with comments we received from the TEC and the Public Interest Advocacy Centre (PIAC) on a draft version of this submission. They both suggested that any amendments to our reliability standards should for DER integration should flow from the outcomes of the DEIP initiative and only once any rule changes deriving from this at the national level have been finalised.

Incentives for integrating DER

The ability of customers to export energy back to the grid can be constrained in some locations where DER penetration is high. When this happens, there is little incentive for networks to invest in measures to reduce DER export constraints under the current regulatory framework. Under the current framework there are in fact disincentives to investment in DER hosting capacity. This was clearly articulated by the Australian Energy Market Commission (AEMC) in its 2019 Electricity Network Economic Regulatory Framework Review:

> …even if network revenue allowances have been built up on the basis of constraints being addressed then, in the absence of a countervailing output incentive, the operation of incentive schemes such as the efficiency benefit sharing scheme (EBSS) and capital efficiency sharing scheme (CESS) incentivises under-expenditure, with no penalty for under-delivery.[3]

Despite regulatory incentives to the contrary, network businesses across Australia are nonetheless attempting to alleviate DER export constraints affecting customers. For instance, Ausgrid is planning a trial of a community battery. This is a local battery operating

2 https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program/
3 AEMC, Electricity Network Economic Regulatory Framework Review, September 2019, p. xi.

‘in front’ of the meter, within which customers can store excess solar PV energy for their local community to access at a later time. Community batteries can also provide value across various layers of the supply chain; for example, through trading of locally generated energy in wholesale markets.

More formal incentives for integrating DER are, however, needed to maximise the net benefits of customer owned generation and storage. These incentives should allow networks to retain at least part of the difference between the cost of optimising DER export capacity and the net market benefits that this delivers. Consistent with the RIT-D process, the net market benefits should be considered across the entire electricity supply chain, including reductions in wholesale generation costs which an upgrade to DER hosting capacity can help deliver for customers.

Stand Alone Power Systems

The AEMC is due to publish a final report proposing rules for a new DNSP-led SAPS framework in May 2020. The proposed regulatory changes are likely to require:

- jurisdictions to ‘opt in’ to the new arrangements after ensuring that energy-specific consumer protections apply to customers who move to a distributor-led SAPS; and
- IPART to consider how our Licence Conditions should be updated so they apply to SAPS customers.

Our view is that reliability standards should be set to ensure no SAPS customer is worse off than they were when connected to the distribution network. Others, however, may have a different view. In commenting on a draft version of this submission, the TEC noted that some SAPS customers may want to trade off reliability for greater control or autonomy. This indicates that further discussion may be needed on this issue. It will also be important for IPART and the NSW Government to take steps to minimise delays in opting into the national framework to ensure NSW networks are able to utilise SAPS where it is the most efficient option.

In our submission to the AEMC’s SAPS priority 2 – consultation paper, we submitted that consistency of approach across distributor-led SAPS, embedded networks and third party led SAPS should be a priority, and that this would allow customers to more easily determine their consumer protections and supplier obligations. We maintain this view.

Refocus on worst served customers

IPART’s review provides an opportunity to address some of the deficiencies with the Service Target Performance Incentive Scheme (STPIS) in incentivising improvements in the reliability for the worst served customers.

The STPIS is a mechanism used by the AER to assign value to reliability of electrical supply to customers. The incentive scheme penalises or rewards Ausgrid financially based on measurements of duration (SAIDI) and frequency (SAIFI) of power interruptions.

The current version of the STPIS does not measure absolute reliability performance a customer receives. Instead, incentives are based on the relative improvement in the average reliability experienced by customers on each feeder type. This measurement method, based on average relative performance, provides no direct incentives for individual customers who have historically received below average reliability. IPART's review could address this by considering how our reliability standards could provide a more robust 'safety net' for the worst served customers.

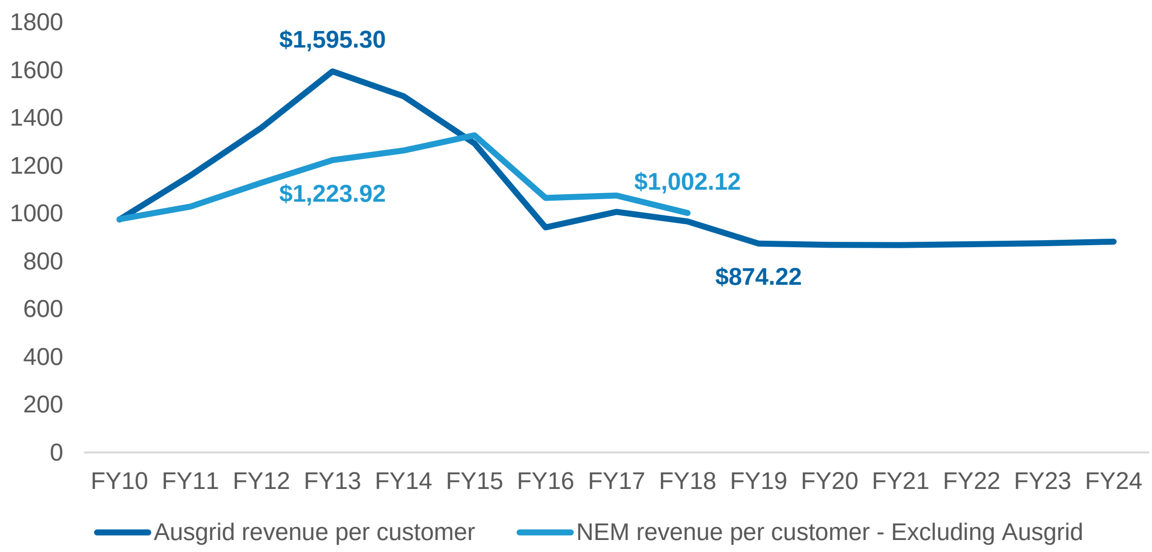
The treatment of customers in embedded networks under the STPIS should also be considered. Under the current STPIS, the loss of supply is only attributed to the parent meter in an embedded network. This understates the number of customers who have been impacted by an interruption. For example, an apartment block with 50 customers in an embedded network will currently have just one customer recorded as losing supply when a network interruption affects them.

Affordability and reliability

Since our reliability standards were last reviewed, we have made significant progress towards improving affordability while still maintaining a level of reliability in line with what our customers expect and value.

Figure 4 shows that our annual revenue per customer has fallen 45% from its peak in FY13, and that while we were once well above our peers on this measure of affordability, we are now below the national electricity market (NEM) average. Figure 5 charts the changes in our reliability. It shows that over the same period in which our revenues declined on a per customer basis, we have improved both SAIDI and SAIFI.

Figure 4 Annual total revenue per customer ($FY20 real)[4]



4 Revenue per customer based on total revenue and all customers (residential, commercial, industrial).

Figure 5 Benchmark SAIDI and SAIFI performance

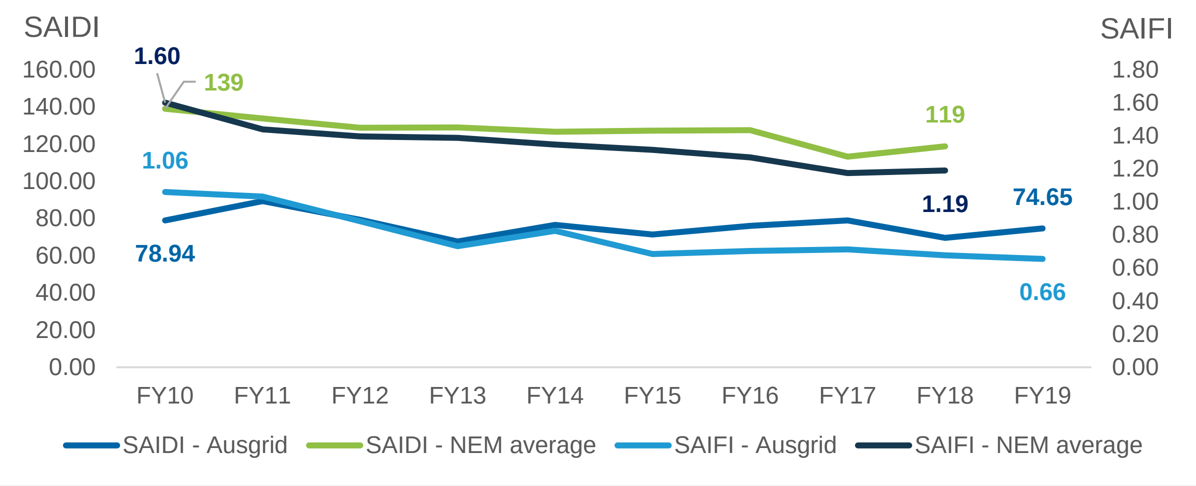
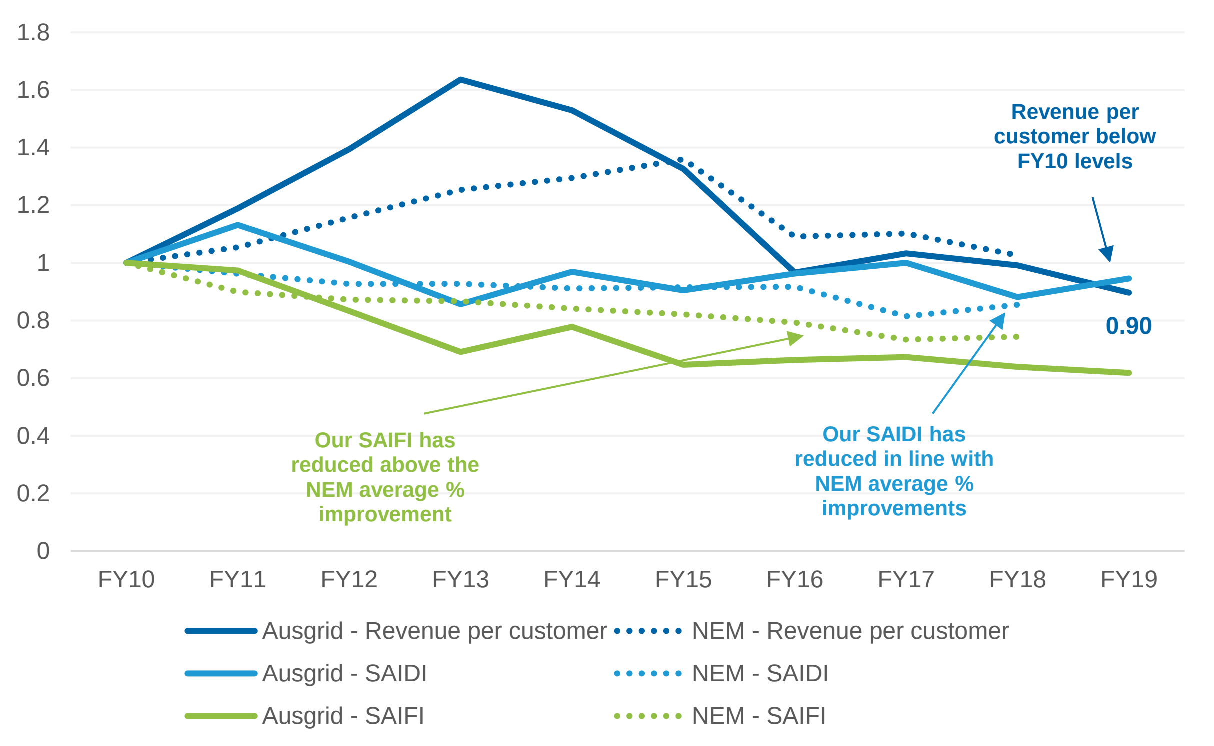


Figure 6 is based on the same data as the figures above. But instead of presenting the absolute changes in revenue per customer and reliability, the rate of change is tracked in percentage terms relative to FY10 performance.

Figure 6 Revenue per customer and reliability improvement (% change)



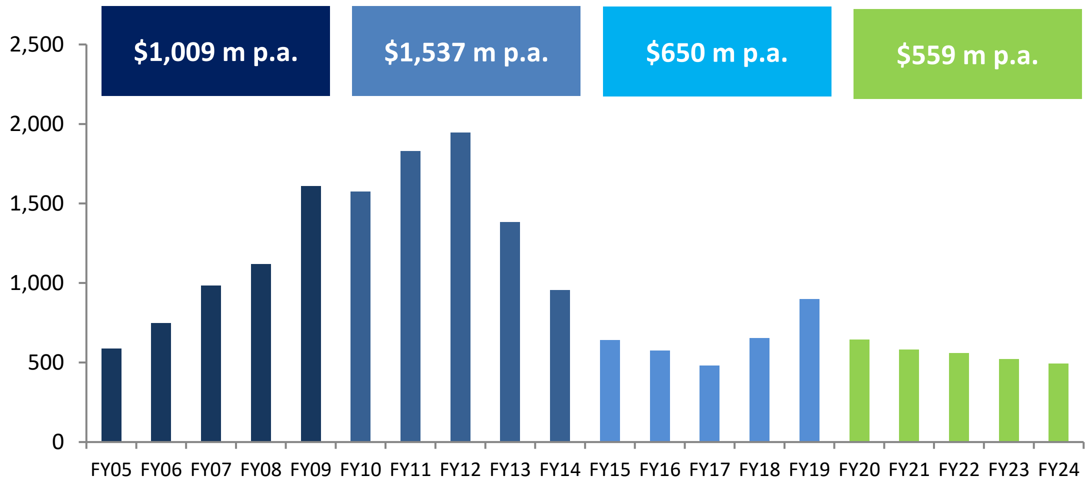
Based on the above, our revenue per customer, while significantly higher in past years, is now below FY10 levels. At the same time, the reliability on our network has improved in line with what other electricity distributors in the NEM have been able to achieve. As shown in Figure 6 above, both the frequency (SAIFI) and duration (SAIDI) of outages on our network have reduced since FY10 at a rate similar to our peers – although our SAIFI improvement has been above the NEM average.

We consider this simultaneous improvement in affordability and reliability, not just for Ausgrid but across the NEM, indicates that the current regulatory economic framework administered by the AER is broadly meeting its objectives in terms of promoting the long-term interests of customers. We elaborate further on this below.

Moving to a more sustainable level of capex

Our forecast annual capex in the FY20-24 regulatory period, as approved by the AER, is $599 million (real FY20). This is lower than the average in FY15-19 ($650 million) and substantially lower than the annual average capex in FY09-14 ($1,537 million) and in FY05-09 ($1,009 million)

Figure 7 Historical and forecast capital expenditure ($m, real FY20)



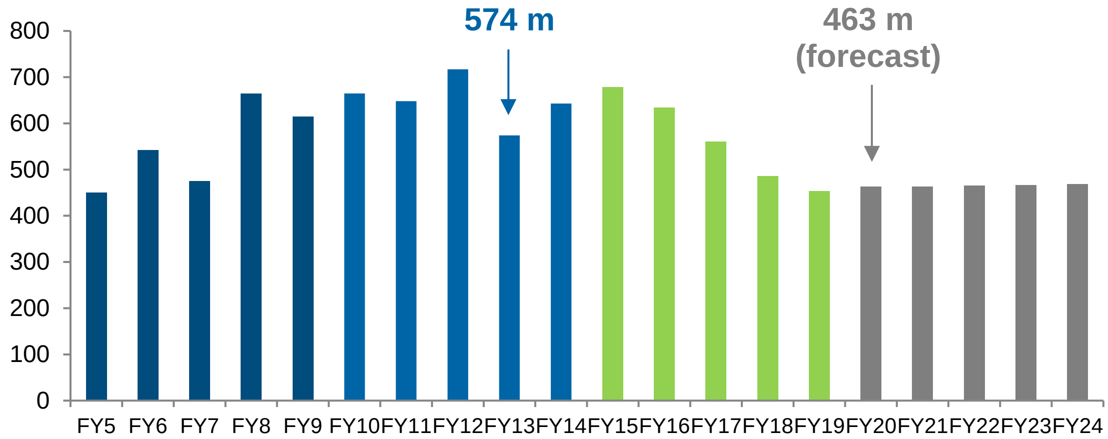
In past years, underinvestment in the 1990s and 2000s led to a significant rise in the need to invest in the replacement of ageing assets. This began in FY05 and peaked in FY12. Deterministic reliability planning also created regulatory obligations to meet mandated levels of reliability – triggering higher investment.

We are no longer faced with these conditions. Broad based underinvestment on the scale that existed in the early 2000s does not exist today, and deterministic planning standards have been removed.

Unlocking significant operating cost savings

We have unlocked significant operating cost savings from our business in recent years. Our forecast for the FY20-24 regulatory period embeds a 19% reduction in real terms in our operating expenditure (opex) compared to 2013 levels. This amounts to a recurrent annual opex saving for customers of more than $100 million per year, as shown in Figure 8.

Figure 8 Historical and forecast operating expenditure ($m, real FY20)



Economic modelling

Our preliminary comments on the economic modelling approach to setting reliability standards, as flagged by IPART in the Issues Paper, are raised below.

These comments draw attention to the probabilistic planning tools already in use at Ausgrid and cautions against inadvertently reintroducing elements of deterministic planning. We also provide high level commentary on the economic modelling approach IPART developed to set TransGrid's reliability standards.

Probabilistic planning currently in use

Following the removal of deterministic reliability standards in 2014, Ausgrid has moved to a probabilistic approach to planning our network. As outlined below, this approach aligns to industry and AER standards and has been independently verified to be based on sound economic principles of cost-benefit analysis.

At this stage, we have concerns that any benefits associated with IPART running its own economic modelling in addition to ours, would be outweighed by the costs to IPART and all three NSW electricity distributors. These concerns are outlined in further detail below.

<u>Replacement expenditure</u>

Our replacement expenditure (repex) is the largest component of our capital investment program. For the 2019-24 period, our repex is forecast to be $1,399 million or 52% of our total approved capital investment of $2,690 million (real FY19).

We apply economic tools and analysis to making repex investment decisions; the key input into which is calculating a 'monetised value of risk'. Figure 9 summarises our approach to making this calculation. It shows that we consider multiple risk areas – including a monetised value of 'network risk' that is based on the probabilities associated with a network failure and the consequences of that risk in terms of unserved energy. We also calculate monetised values for other risk areas – including safety, fire, the environment, and financial risks such as penalties.

Figure 9 Our approach to asset investment decision making [5]

We then undertake a cost-benefit assessment to compare the replacement costs of an asset and the monetised risks associated with the asset failing. Significantly, as shown in Figure 9 above, a wide range of factors feed into the probability and consequence of failure. These include information on current failure rates, incident histories and verification tests using benchmarks and subject matter expertise.

To proceed with an investment, the risk mitigated (the benefit) must exceed the replacement cost. Figure 10 sets out this cost-benefit evaluation in the form of an equation. Based on it, all assets in a given year with a risk value greater than the annualised replacement costs (i.e. an investment evaluation ≥ 1) would be considered for replacement.

Figure 10 Cost-benefit equation[6]

Our risk-based approach to network investment aligns to *ISO31000: Risk Management* and the AER's *Industry Practice Note for Asset Replacement Planning*. Ahead of submitting our 2019-24 proposal, we also engaged Frontier Economics to independently assess the economic approach we undertake, who found that the method we use to assess the appropriate timing of replacement investment 'conforms to sound principles of cost benefit analysis'.[7]

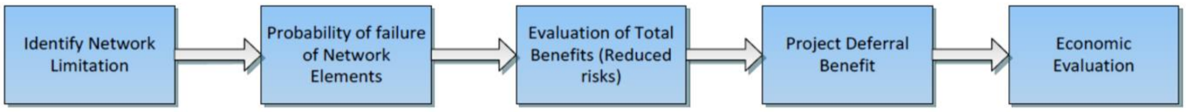
5 Ausgrid, Revised Proposal for 2019-24 period, Attachment 5.01, p. 26 (Link to Source)
6 Ausgrid, Revised Proposal for 2019-24 period, Attachment 5.01, p. 26 (Link to Source)
7 Frontier Economics, Review of Ausgrid CBA models, January 2019 (Link to report)

Augmentation expenditure

Augex is a relatively small part of our investment program. For our 2019-24 period, it is forecast to be $215 million, or about 8% of our total forecast investment ($2,690 m).

We use cost benefit analysis techniques to forecast our augex requirements. Figure 11 maps a simplified outline of the network investment and planning process that we follow. Each step in this process moves towards an economic evaluation that factors in the benefits (reduced risks) of a potential augex investment.

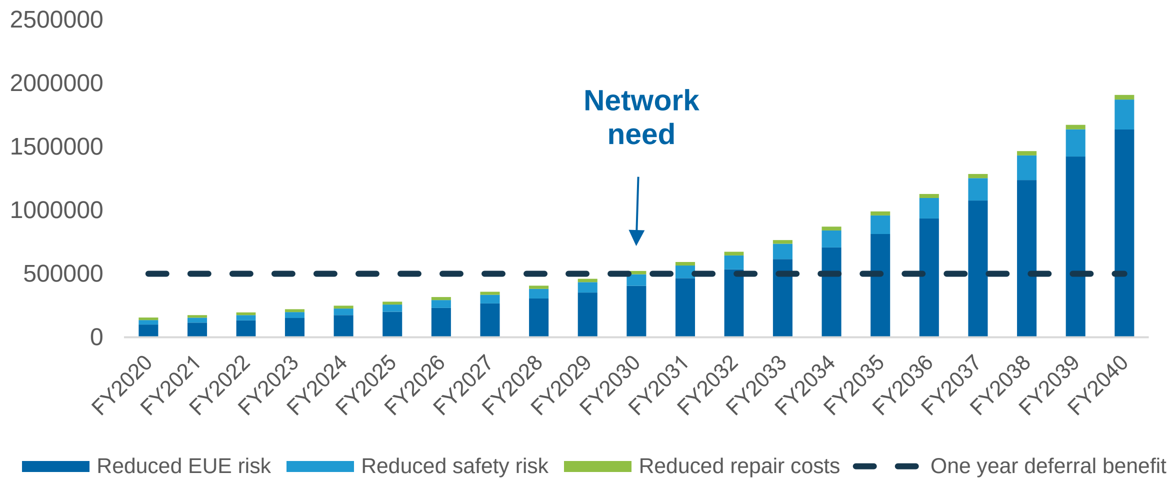
Figure 11 Simplified cost benefit analysis process



For major projects, the economic evaluation we undertake factors in multiple benefits. These include the monetised benefits of reduced Expected Unserved Energy (EUE), reduced safety risk, reduced maintenance and repair costs, and reduced environmental risks.

Where possible, the timing of a project is chosen to maximise the net economic benefit to those who produce, transport and consume electricity. This is done by considering the potential timing of the proposed project cash flows and monetised benefits. When the benefits of a project outweigh the possible savings from deferring capital expenditure, and those benefits are forecast to continue, the project is said to be "needed" at that time. This cross-over point is shown in Figure 12.

Figure 12 Total risk costs versus project deferral benefits ($,constant)



The next step, having identified the network need date, is to assess the available options. The net economic benefit of each option identified in our Area Plan review is calculated as illustrated in Figure 13 below. The option with the maximum net economic benefit, subject to a consideration of other risks, is chosen as the preferred option.

Figure 13 NPV analysis for options comparison

The analysis above is critical for major projects at the subtransmission level, where the deferral benefits of a project can be significant. These benefits, however, are substantially smaller at the low voltage (LV) and high voltage (HV) segments of our network, where the deferred EUE and other benefits will not be as significant and may not be quantified as part of our planning process.

More detail about our approach to forecasting augex project was provided to IPART in April 2020 in response to an information request. We consider our approach to be robust and based on sound principles of cost-benefit analysis.

Potential risks with modelling approach

Our probabilistic approach to network planning is set up to identify the most efficient level of investment based on the forecast costs and the monetised value of risks relating to reliability. This results in our investments aligning to the objectives of the economic model flagged by IPART in its Issues Paper – this being, the identification of a level of reliability that achieves the lowest 'social cost'.

We are concerned that developing an additional economic model, to be run in parallel with our own economic analysis, would not improve affordability or otherwise help Ausgrid identify the most efficient level of investment. Any additional regulatory obligations could increase our compliance costs that are, ultimately, recovered from customers. There is also a risk of unintended consequences that could put upward pressure on our investment requirements and inadvertently increase costs for customers. Before proceeding further, it may be prudent for more analysis to be undertaken. The AEMC recently conducted a cost benefit review of a major reform involving the Coordination of Generation and Transmission

Investment (COGATI).[8] IPART could consider undertaking similar cost benefit analysis in relation to its flagged modelling approach.

Elements of deterministic planning

The setting of reliability standards based on an economic model risks creating rigid investment obligations that may be akin to deterministic planning.

The AER is required under the National Electricity Law (NEL) to set an electricity distributor's revenues in a way that allows it to recover at least the efficient cost of complying with all regulatory obligations – including any reliability standards set by a jurisdictional regulator.[9] This gives rise to a risk that IPART's economic modelling of reliability outcomes could bind the regulatory decision making of the AER.

We would have significant concerns if this happened. No matter how sophisticated or robust, a single model should not replace or diminish the two year process the AER currently undertakes to set the NSW electricity distributor's revenue allowances.

Economic tools are important but they cannot substitute the outcomes of extensive stakeholder consultation, including with customer representatives, we undertake when preparing a regulatory proposal and on an ongoing basis. Nor can economic tools gauge any changes in customer preferences that can only be revealed through consultation.

Replacing or diminishing the multiple assessment tools used by the AER with a single model also increases the risk of error. This could lead to overinvestment that impacts affordability in the short term; or an initial period of underinvestment that creates reliability and affordability challenges over the longer term when a large volume of ageing assets fails and has to be replaced simultaneously.

TransGrid's model

We have undertaken a preliminary review of the economic modelling that IPART used to determine the reliability standards that now apply to TransGrid. This has raised concerns for us about the viability of taking a similar modelling approach to setting our reliability standards.

In terms of the data inputs, we observed that IPART's transmission modelling includes a range of assumptions about network parameters relating to average feeder length and the average cost / time to repair network faults, among other things. Our preliminary position is that the use of similar assumptions based on averages is unlikely to be suitable for IPART's distribution model. This is given the greater level of complexity and volume of disparate network elements on our network. We, however, look forward to further collaboration with IPART on these matters as its modelling approach advances.

From a more practical point of view, we have also considered how IPART's transmission modelling could promote affordability for our customers by influencing how we plan our

8 https://www.aemc.gov.au/sites/default/files/documents/nera_benchmarking_consultant_report_-_aemc_transmission_access_reform_-_march_update.pdf

9 National Electricity Law, section 7A(2)(b).

distribution network. When considering this, it should be emphasised that our reliability standards currently trigger an investigation only, not a network investment. This is in line with our approach to only model EUE at a specific location on our network when a constraint has been identified.

The majority of investigations triggered by our current reliability standards are in our Urban and Short Rural SAIDI category, which make up more than 90% of our customer base. Each feeder within these categories and their SAIDI performance are set out in Figure 14 and Figure 15 below. The shaded red area in both charts shows the SAIDI that triggers an investigation of a feeder as per our ***current*** reliability standards. Investigation of a feeder may, but does not necessarily, lead to a network investment.

Figure 14 Urban SAIDI performance and current reliability performance

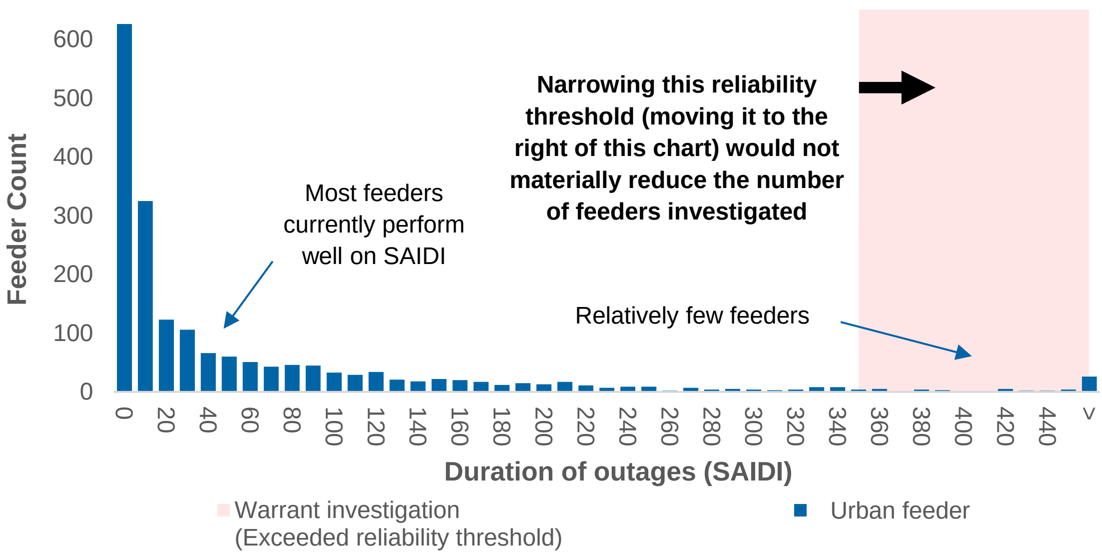
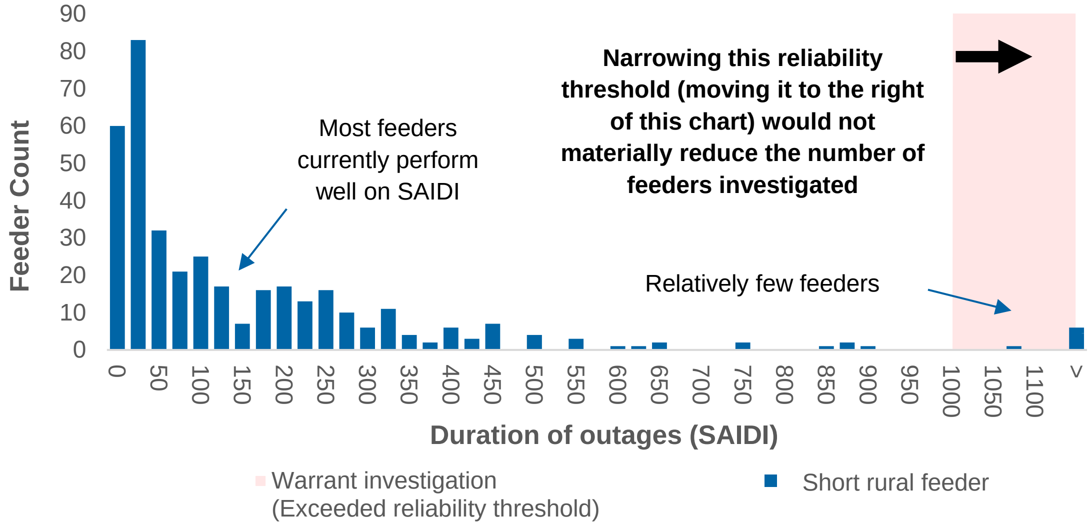


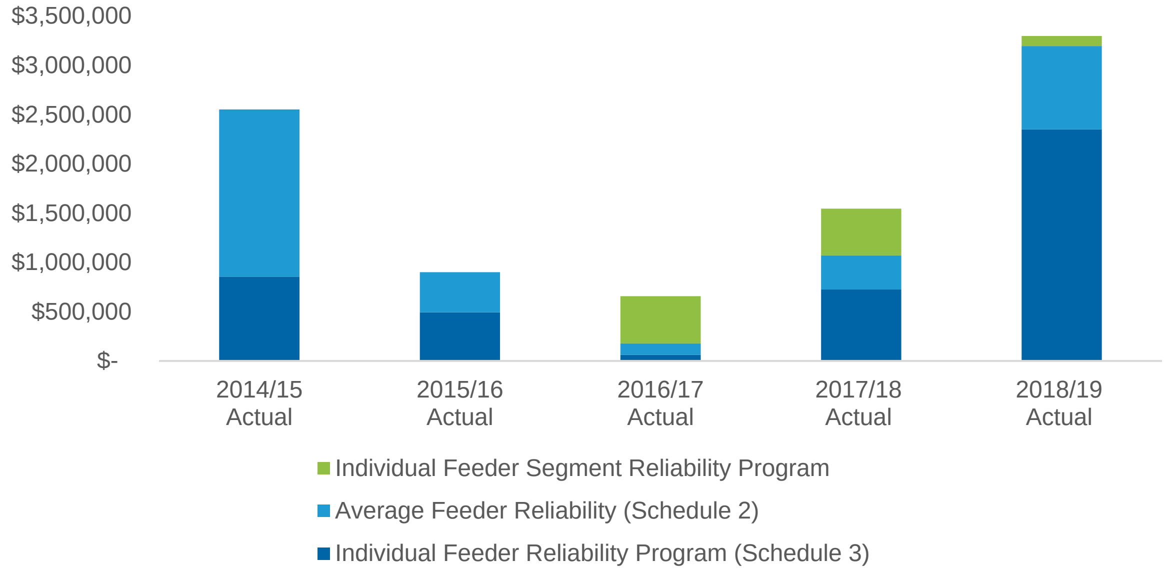
Figure 15 Short Rural SAIDI performance and current reliability performance



The charts above show that a reduction to our current reliability thresholds, aimed at promoting affordability, would not materially change the number of feeders we would investigate for potential network investment. This is due to the low number of Urban and Short Rural feeders lying within the ***existing*** reliability threshold (red shaded areas in Figure 14 and Figure 15). From a practical perspective, this means the number of feeders we investigate for potential network investment is unlikely to materially change if IPART took steps towards reducing our current reliability standards (i.e. narrowing the red shaded areas above).

It follows that the scope to deliver cost reductions in this area of our investment program is relatively small. In some instances, an investigation triggered by our reliability standards will lead to a network investment. However, our annual capex in this area is only about $1-3 million per year, as shown in Figure 16, or between 0.3% and 0.5% of our total annual capital program.

Figure 16 Investments driven by reliability standards ($nominal)



We are committed to delivering cost savings for our customers through the identification of efficiencies and using robust economic analysis to underpin our investments.

Based on our review of IPART's transmission modelling, we are nonetheless concerned that applying the same approach to setting our reliability standards may not yield benefits for customers in terms of promoting affordability. Before pursuing this approach further, we suggest that IPART considers undertaking a cost benefit assessment. This could test whether the economic modelling approach flagged in the Issues Paper would lead to benefits for customers that outweigh the additional regulatory and compliances costs that it would introduce.

Part 2: Issues Paper Questions

Question 1

Do you agree that SAIDI and SAIFI measures should continue to be used in the reliability standards, defined in line with the AER's Distribution Reliability Measures Guideline?

We support the continued use of SAIDI and SAIFI. They are well defined measures that the NSW and other electricity distributors have been reporting on for several years. Switching to a new measure of reliability, such as EUE, would be disruptive in terms of our regulatory compliance and would lead to difficulties in benchmarking our historical reliability performance against our peers in the NEM. This would increase compliance costs, with limited benefits for customers.

SAIDI and SAIFI are also based on factual data. By contrast, EUE is not strictly measurable but instead reliant on an estimate of how much energy would have been used having regard to a range of assumptions.

Question 2

Do you agree that we should convert our estimate of the efficient level of expected unserved energy to allowances for the duration and frequency of interruptions? How could we convert the efficient level of expected unserved energy to allowances for the duration and frequency of interruptions?

We agree that our reliability standards should continue to be based on the duration (SAIDI) and frequency (SAIFI) of interruptions but have concerns about IPART using an economic modelling approach to set these measures.

Ausgrid has already put in place economic modelling tools that are set up to identify the most efficient level of investment, based on the forecast costs of the available options and the monetised value of risks relating to reliability. We are concerned that developing an additional economic model, to be run in parallel with our own economic analysis, would not improve affordability or otherwise help Ausgrid identify the most efficient level of investment. Rather, there is the risk that an additional economic model would increase our compliance costs that are ultimately recovered from customers, and may create rigid investment obligations that may be akin to a reintroduction of deterministic planning standards.

The approach flagged by IPART in the Issues Paper would also be highly reliant on modelling the costs and benefits associated with each feeder. This would be a highly data intensive task requiring access to Geographic Information System (GIS) modelling, changes to future loads and connectivity, unit costs, among other things. Rather than doing this for each feeder across our entire network, it is far more efficient to run these assessments in only the poorest performing areas. In line with our current planning approach, this will then prompt site-specific investigations.

We recommend IPART focuses its attention on the deficiencies of the current version of the STPIS, such as dealing with worst served customers and the treatment of embedded customers. There is also a need to consider network resilience in the face of increased extreme weather events and work on the management of ‘two-way’ energy flows. More detail about our concerns and recommendations are included in Part 1 of this submission.

Question 3

Do you agree that the excluded events in the distributor’s licences should be consistent with the AER’s Distribution Reliability Measures Guideline and Service Target Performance Incentive Scheme? Are there any additional events that should be excluded by the licence or any events that should not be excluded?

We agree that excluded events in our Licence Conditions should align to the AER’s Distribution Reliability Measures Guideline (DRMG) and STPIS. We would add that all reliability performance measures in our Licence Conditions more broadly should align with not only the DRMG and STPIS, but also the AER’s Regulatory Information Notices (RINs). This would streamline the effort spent on compliance activities for both regulators and the NSW electricity distributors, and ultimately promote affordability for customers by reducing regulatory reporting costs.

Question 4

If there is a risk that the frequency of severe weather events will increase, how should the costs of providing a resilient network and the value customers place on this resilience be balanced and what requirements should be placed in the distributors’ licences?

Climate change is exacerbating inherent risks in Australia’s climate and is leading to an increase in the frequency and severity of extreme weather events and bushfires. Over the long-term this presents the single greatest risk to our ability to provide reliable and affordable services.

As noted in Part 1 of our submission, IPART’s review offers an opportunity to take into account the effects of climate change and examine the relationship between weather events and bushfires, network reliability and affordability from a customer’s point of view. To do this, we would like to work with IPART to better understand customer expectations and willingness to pay for networks that are resilient and able to endure the expected increase in extreme weather events. This data could then be used to inform network planning outcomes so that our investment decisions align to what our customers value in terms of the balance between long-term affordability and reliability.

Question 5

Do you agree that payments under customer service standards should reflect the cost to a customer of an outage? How would this best be measured or estimated?

We recognise that there may be benefits to payments under service standards reflecting the cost of a customer outage. We look forward to continuing to engage with IPART on how this could be done. The methodology for measuring or estimating payments should take into account the cost impacts on other customers (if any).

Question 6

Should payments under customer service standards increase as the duration (or frequency) of an outage (or outages) increases? Should payments be automatic or continue to require application by a customer? If payments become automatic, should exclusions be based on the major event day measurement that currently applies to the other reliability standards or continue to be defined causally (i.e., with reference to extreme or severe weather as defined by the Bureau of Meteorology)?

Customer service standard payments should reflect the value customers place on energy. It follows that these payments should be higher for outages that last longer or in circumstances where a customer experiences them more frequently. There should, however, be a cap on maximum payments that reflects the AER's finding in its 2019 VCR review that customers place less value on reliability the longer an outage lasts.[10]

We would have concerns with making payments automatic. Given that retailers have the main financial relationship with customers, it is likely to be administratively difficult to make payments automatically. This is because any financial payments will have to be made through retailers, and costly changes to IT systems are likely to be required in order to achieve this.

There is also the risk of automatic payments leading to overcompensation. When there is an interruption at the LV level, we currently do not have clear visibility of who is impacted. In the absence of a mass deployment of smart meters it highly likely that an automatic payment scheme would lead to networks compensating customers who are unaffected by an outage.

We should note, however, that prior to lodging this submission with IPART we shared a version with customer representatives sitting on our CCC. In relation automatic payments, the Council of The Aging commented

> It is our experience that the senior community (and probably the residential community generally) is unaware of service guarantees and the availability of payments for failure of obligations and so support automatic payment for residential customers.It should be feasible to design arrangements to ensure that compensation occurs as and where appropriate. It seems suitable that such payments would be based on the frequency and duration of outages.

10 AER, Final Decision on VCR review, December 2019, p. 65.

Question 7

How should reliability standards cater for new technologies such as Stand-alone Power Systems?

As noted in Part 1 of our submission, the AEMC is due to publish a final report proposing rules giving effect to the new DNSP-led SAPS framework in May 2020. These regulatory changes will require IPART to consider how our Licence Conditions should offer protections to SAPS customers.

Our view is that reliability standards should be set to ensure no SAPS customer is worse off than they were when connected to the grid. We would support our Licence Conditions providing this clarity. It will also be important for IPART and the NSW Government to take steps to minimise delays in 'opting in' to the framework to ensure NSW networks are able to utilise SAPS where it is the most efficient option.

Question 8

Should network reliability standards take account of two-way energy flows and the ability of the network to allow customers to both buy and sell electricity? If yes, should reliability standards take into account the value to customers of being able to export or sell power to the grid? What might this look like in practice?

As more customers install DER, there is an emerging need to consider how two-way energy flows should be taken into account in our Licence Conditions. There is, however, considerable work being done on this issue that has yet to be finalised.

In particular, the DEIP Access and Pricing initiative is a national collaboration between policy makers, industry and consumer representatives, tasked with the goal of building consensus on equitable and efficient DER access and pricing models. Though we fully support engaging with IPART on how the emergence of two-way energy flows should be recognised in our Licence Conditions, in our view IPART should exercise caution in making a final determinations on this matter until the DEIP initiative has been completed and any resulting rule changes have been made by the AEMC. This will ensure consistency between the national collaborative effort, conducted via DEIP, and any changes to our reliability standards that are made by IPART at the jurisdictional level.

We also shared a version of this submission with stakeholders before submitting it to IPART. In terms of the cost of DER and how it is funded the COTA commented that:

> Climate change and uptake of solar generation has been proceeding over some years and while review is appropriate one would anticipate that contingencies to address these developments would be already at a stage of some advancement.
>
> It is agreed that investment to accommodate solar generation, storage and export are valid areas for investment. However, in progressing such investment it is necessary to recognise and manage the risk that these customers could be unreasonably subsidised by others in the

market who are more likely to encompass seniors and other economically vulnerable groups.

We agree with COTA that issues related to equity need to be considered. This is particularly with regard to the impact that changes to our Licence Conditions could have on non-DER customers and the price they pay for electricity

Question 9

Do you agree with our proposed approach to estimating the efficient level of reliability and basing the standard on the level that delivers the lowest social cost?

We have concerns that IPART's proposed approach may not be an effective way for setting reliability standards for a distribution, as opposed to a transmission, network.

The approach put forward in the Issues Paper would require extensive modelling and assumptions about the efficient level of reliability at each element of our network. While transmission networks may undertake this approach for each of their bulk supply points, this is not a network planning approach that Ausgrid applies, nor is it common among electricity distributors more generally.

We have over 2,300 feeders on our network. Rather than investing the time and resources to estimate EUE at each of these elements of our network, our planning approach limits our assessment to the poorest performing areas. Where we identify risks to reliability, we will then conduct a site-specific investigation. We consider this to be a prudent and efficient approach to making distribution network investment decisions. It, however, means that the depth of analysis that IPART's flagged approach would expect to be done for every element of our network, is only done when a risk has been identified.

Before proceeding further, we suggest IPART considers whether its flagged approach would introduce elements of transmission planning to our reliability standards that do not reflect how distribution network investment decisions are made. Our concern that this could lead to unintended consequences that could challenge the NSW electricity distributors ability to promote affordability and reliability for our customers.

We also suggest that IPART considers undertaking a cost-benefit analysis of its flagged approach. This should take into account the additional costs associated with new regulatory, compliance and planning requirements that would be introduced for IPART and all three NSW electricity distributors.

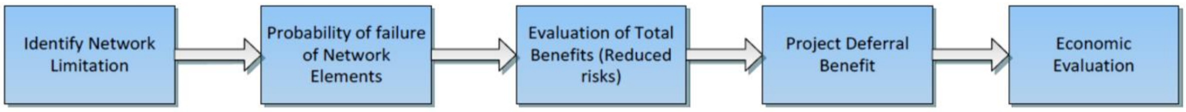
Question 10

How should we estimate expected unserved energy across distributors' networks (for example by area, substation and/or feeders)?

We have concerns about the feasibility and resource-intensiveness of developing reliability standards based on estimated EUE at specific locations or components of our network.

Figure 17 below, taken from Part 1 of our submission, maps a simplified outline of our investment and planning process for augex projects. Each step in this process moves towards an economic evaluation that factors in the benefits (reduced risks) of a potential augex investment.

Figure 17 Simplified planning and investment process



Under this approach to network planning, we will only undertake a risk-based quantification of the benefits associated with a potential investment, including reduced EUE, when a network need has been identified. This need could be related to reliability and thus EUE, or it could be driven by a safety, environmental or other need that has been identified during our regular maintenance and inspection activities.

What this means in practice is that our network planning decisions are not based on a system wide calculation of EUE at every location on our network. A potential investment need must first be triggered before estimated reductions EUE will be considered as part of our cost-benefit analysis. Nor do we consider EUE at the more granular network element (substation, feeder) prior to the identification of a potential investment need.

Taking into account our current practices, we consider the approach flagged by IPART would be highly resource intensive. An attempt to derive efficient reliability standards based on individual network components also risks producing inaccurate outcomes given the highly dynamic nature of distribution networks, with their mesh nature providing substantially more 'switching' capabilities than in transmission

Question 11

Do you agree with our proposed approach to estimating the following inputs:

- **the cost of expected unserved energy, which is a result of:**
  - **the value customers place on reliability (VCR)**
  - **the probability of asset failures**
  - **the duration of outages and restoration profile**
  - **profile of demand at each location**
  - **number and capacity of transformers and feeders and/or non-network options**
- **the direct costs (operating and capital costs) of providing different levels of reliability, and**
- **a discount rate and asset lives to convert capital costs to an annuity.**

We foresee data challenges in applying the approach flagged in the Issues Paper.

Chief among these, is that we do not model EUE for every element of our network. We instead focus our attention on the poorest served areas and then, when we have identified an issue, spend the time and resources to conduct the site-specific analysis required to identify the least cost investment options. We consider this approach to distribution network planning is prudent and efficient. However, it does mean we only have detailed information on EUE at locations where a reliability issue has been identified. Robust information on reliability levels at all other locations, as would be expected by IPART's flagged approach, may not be readily available.

There is also inherently greater complexity associated with distribution, compared to transmission, networks. Adjusting for this complexity will be a significant undertaking and will require information on elements of our network that we presently do not report to IPART or to the AER, via regulatory information notices (RIN).

Other data quality issues are likely to emerge. Our understanding is that IPART spent significant time working with TransGrid in the development of the modelling approach and inputs that eventually fed into its current reliability standards. We welcome the level of collaboration IPART has offered Ausgrid to date, and look forward to that continued engagement.

In providing input into a draft version of this submission, the TEC noted that there are potential gaps in the AER's VCR framework between short-term localised outages and long widespread outages. The TEC then noted that as severe weather events become more common due to climate change, more outages are likely to fall outside the normal reliability standard at the same time that they are having a greater impact on customers. Further work on how these outages are incorporated into the regulatory framework and any modelling of the NSW electricity distributors' reliability standards may need to be undertaken.

Question 12

What role does including reliability standards in licences play and do you agree that the standards should minimise any duplication of incentives between the NSW distributor licences and national regulatory framework?

Duplication that distorts the incentives for networks to make efficient investment and operational decisions in the NER framework should be avoided. This is best achieved by the licences maintaining a 'safety net' level of minimum reliability for customers.

Question 13

What is the appropriate compliance framework for monitoring performance against distribution network reliability standards? Should IPART have the flexibility to determine the frequency of reporting, in response to performance?

Yes, in our view IPART should have the flexibility to determine the frequency of reporting.

Consistent with reporting obligations under the transmission reliability standard, in our view the NSW distributors should also report annually on our performance.

Thank you