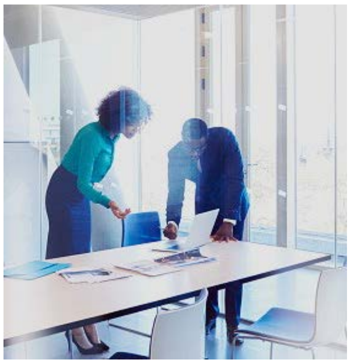
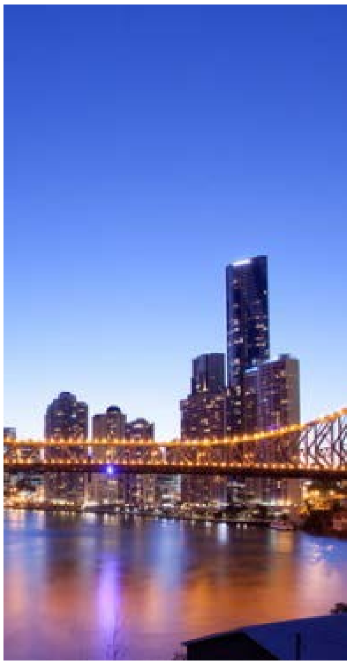
# Revised Proposal Attachment 5.13.L.1 GHD Independent Review of the Network Innovation Portfolio PUBLIC

January 2019

GHD Advisory





# Independent Review of Innovation Program Cost Benefit Analysis

Ausgrid

04 January 2019

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# 1. Executive summary

Innovation plays a key role in competitive markets and is funded accordingly, with technology and healthcare firms amongst the biggest spenders of Research and Development funds. In regional monopolies the impetus to fund research, trials and experiments is less obvious and in electricity networks it was historically non-existent. A confluence of forces such as disruption, consumer choice, climate change and affordability concerns are driving forced changes to traditional “poles and wires” businesses, not just in Australia but globally.

Ausgrid has identified eleven innovation projects in its most recent regulatory proposal worth a combined $42 million of capital expenditure. In decreasing order of value, they are:

1. HV Microgrid Trial, $17.2 million.
2. Network Insight Program, $10.5 million.
3. Fringe of Grid Optimisation, $4.7 million.
4. Advanced Voltage Regulation, $3.0 million.
5. Grid Battery Trials, $2.0 million.
6. Advanced EV Charging Platform Trial, $1.2 million.
7. Portable All-in-One Off-Grid Supply Units, $1.0 million.
8. Self Healing Networks, $0.6 million.
9. Dynamic Load Control, $0.6 million.
10. Asset Condition Monitoring, $0.6 million.
11. Line Fault Indicators, $0.6 million.

Collectively, the projects are forecast to deliver a 10 year Net Present Value of $46.9 million over the next ten years. Just over 90% of this value is attributable to the Network Insights Program, Fringe of Grid Optimisation and Advanced Voltage Regulation projects.

In the recent draft determination, the Australian Energy Regulator (AER) did not accept the proposed network innovation expenditure on the basis that insufficient information was provided for it to evaluate the program against the capital expenditure criteria of the National Electricity Rules (NER). Ausgrid has since conducted more detailed Cost Benefit Analysis (CBA) and engaged GHD Advisory to conduct an independent review of that CBA. This report outlines our evaluation of the program and individual project CBAs.

In summary, we found the project justifications and CBA costs, unit rates and assumptions to be reasonable. The basis of the benefits estimates was sound, however in some cases the scope of benefits could be expanded to include environmental benefits and other externalities. We also considered some of the input assumptions to the benefits calculations erred on the conservative side. We considered this tendency to take a mostly conservative approach to benefits estimation is appropriate given the uncertain nature of these types of projects.

We noted that the majority of costs fall in the upcoming regulatory period, but the majority of benefits are realised in future periods and that a key role of the governance body must be to ensure that appropriate adjustments are made to future forecasts that are impacted by productivity improvements or permanent or long term capital deferrals.

Other general findings of our review include:

- Where data was available, benchmarking indicated that unit rates, costs and input assumptions are within a reasonable range.
- Some input assumptions (such as feeder failure rates, customer numbers, etc) are conservative as they are based on averages across the network, when in reality the execution of these projects will be in areas that offer greater potential for savings and benefits.
- Where simillar projects have been conducted and the costs published, the comparable projects in Ausgrid's Network Innovation Program benchmark well.
- The proposed Network Innovation Advisory Committee (NIAC) is a positive development and should be an effective mechanism in formalising the involvement of customers in the governance of the program and management of the projects.
- Ausgrid's decision to exclude the innovation program form the Capital Expenditure Sharing Scheme (CESS) is a positive signal of consideration of long term consumer benefit.
- The significant contribution of the program to removing future curtailment of customers from accessing the grid through distributed energy resources is in the long term interests of consumers.
- The projects that provide visibility of network behaviour below the substation level have obvious connections and dependencies with each other as well as with the Advanced Distribution Management System (ADMS) project. Careful management of this projects should be undertaken to ensure that the linkages between them are leveraged to maximum value and avoid duplication.

*"The innovation process involves many stages – from research through to incubation, demonstration, (niche) market creation, and ultimately, widespread diffusion. Feedbacks between these stages influence progress and likely success, yet innovation outcomes are unavoidably uncertain. Innovations do not happen in isolation; interdependence and complexity are the rule under an increasingly globalized innovation system. Any emphasis on particular technologies or parts of the energy system, or technology policy that emphasizes only particular innovation stages or processes (e.g. an exclusive focus on energy supply from renewables, or an exclusive focus on Research and Development [R&D], or feed-in tariffs) is inadequate given the magnitude and multitude of challenges represented by the GEA objectives.."*

Grubler, A., et al., 2012. Policies for the Energy Technology Innovation System (ETIS), Global Energy Assessment – Toward a Sustainable Future. Cambridge University Press, Cambridge.

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# 2. Introduction

GHD Advisory was engaged to independently review the proposed Ausgrid network innovation program projects, which were recently subject to the draft determination by the Australian Energy Regulator (AER). The AER did not accept the program, noting that a lack of information regarding the justification and cost benefit analysis of the 11 projects prohibited the AER from assessing the prudence and efficiency of the program.

Ausgrid provided the AER with cost benefit analysis for the 11 projects in September 2018, which the AER has declared it will consider as part of the Ausgrid revised regulatory proposal. Ausgrid also undertook to engage a consultant to independently review the program, which is the basis of this report.

In this report, we discuss the need for electricity networks to innovate, the challenges they face in doing so and assess the 11 Ausgrid innovation projects against a framework to determine each project's merit and the reasonableness of the cost benefit analysis.

## 2.1 List of Assumptions

We have made a number of assumptions in undertaking this review, including:

1. We have accepted the discount rate applied by Ausgrid without review, as this is outside the scope of our evaluation.
2. We have assumed that the ADMS project, which was not approved in the AER draft decision but is a predecessor for two of the Ausgrid innovation projects, will proceed for the purpose of this review.
3. We accept all data provided to us by Ausgrid as without error for the purposes of this review.

# 3. The Need to Innovate

Once thought to be somewhat immune to disruption due to regional monopoly status and the essential nature of the service delivered, electricity network businesses are now challenged by a rapidly changing environment. The transportation of electricity is still a critical social and economic need, but the expanding sources of generation, bi-directional flows and emergence of new technologies require significant transformation of network assets and network businesses.

In some parts of the world, the response to disruption by technologies such as photovoltaic cells has been policies of deterrence such as:

- Reductions in Feed-in Tariffs and subsidies.
- Taxes, such as the solar tax in Spain.
- Expenditure ceilings, such as those applied in Italy.

In some cases, these actions were designed to protect traditional poles and wires businesses. In others, they were an attempt to reverse the effect of unintended consequences of a previous incentive policy. For example, the Spanish case study began over a decade ago where generous subsidies were introduced in an effort, in part, to replace a failing coal industry and an intent to meet aggressive renewable energy commitments. The surge in installation of solar was compounded by falling technology costs. In 2009, installed capacity (all technologies) in Spain rose to 93,000 MW against a peak demand of 44,000 MW. Policies were quickly put in place to curtail the installation of solar PV and the industry collapsed.

Smart meter uptake is another area where policy has a significant impact on effectiveness. In Victoria, the smart meter rollout was mandated. Lessons from that program have led to different approaches in different states within Australia. Responsibility and ownership also has a significant effect. In the UK, suppliers are responsible for supply and funding of smart meters, whereas the Distribution Network Operators reap most of the benefits. These types of arrangements dictate whether rollouts are actively or passively managed.

There are many cautionary tales of policy-led investment incentives in new technologies going awry, however the answer cannot be to move to the other end of the spectrum. Network businesses and the grid itself are critical enablers of empowerment of customer choice and transition to a lower carbon future. Network service providers must have the incentive to invest in new technologies that can lower prices, increase access, enable smart customers and reduce carbon and network losses.

The widely documented “energy trilemma” highlights the difficulty of simultaneously achieving adherence to our Climate Change commitment, stable supply of energy and mitigation of rising electricity costs. This challenge won’t be met by doing more of the same.

# 4. Constraints on Network Innovation

Since the introduction of the AER’s Better Regulation Program, recent regulatory determinations have focussed on efficiency and productivity – the result of which have been cuts to costs, operating expenditure in particular in NSW and QLD. Whilst downward pressure on price is always in the interest of consumers, and perhaps an inevitable regulatory reaction to political and public opinion on price rises since 2008/09, the long term interests of consumers includes accessibility to the grid and adaptability to their changing energy behaviours. In accordance, network service providers must change the way they manage the grid and regulators must also change the way that they govern that process.

In Australia, regulatory incentives include the Demand Management Incentive Scheme (DMIS) and external agencies such as the Australian Renewable Energy Agency (ARENA) help fund innovative projects that shift energy sources towards renewables. However many of the challenges faced by the network service providers today are in maintaining compliance with existing reliability, quality and security of supply regulations with the injection of an increasing number of new actors in the energy system. Customers acting as generators, aggregators and the forecast increase in electric vehicle use all mean that network service providers can no longer manage customers in a few, large segments (commercial, business, residential). Network businesses must now manage the grid at a more granular level, beyond the substation level right down to the low voltage network. Extant systems, technologies and processes are not currently capable of that.

Whilst there are incentives such as the Efficiency Benefit Sharing Scheme (EBSS) and Capital Expenditure Sharing Scheme (CESS) available to networks, the effectiveness of these incentives when it comes to encouraging investment in innovation can be diminished by:

- Higher hurdles for attractiveness due to the limited return available to the networks (30% under the EBSS and CESS); and
- The constraints of the regulatory control period of 5 years, where capital outlay occurs in the current period but benefits realisation often occurs in future periods.

Regulation of monopoly services has perhaps previously been viewed as a protection for consumers in the absence of competition, but it must now facilitate the enablement of consumer choice. Regulation in other countries has adapted to address broader environmental concerns – such as the Low Carbon Networks Fund (LCNF) in the UK – and these objectives can often coincide with consumer choice. For example, an individual customer may choose solar panels primarily for the cost saving, but the societal benefit extends to an increase in renewables as the source of generation. The shift in motivation behind innovation incentives can be seen through the history of application in the UK by the energy regulator, Ofgem.

- Innovation Funding Incentive (IFI): Introduced in 2004, the IFI aimed to encourage innovation in the technical development of the networks. The incentive was a stimulus for increased network spend on R&D and focused on technical solutions that delivered customer benefit in reliability, quality or security of supply. The IFI was capped at 0.5% of the network operator revenue and allowed for 80% of R&D costs to be passed onto customers. It led to a significant rise in network R&D expenditure between 2004 and 2008, but was not completely taken up, with expenditure in 2008 being 0.33% of revenues. A parliamentary inquiry[1] found that participants suggested that the scope of the projects allowed under the incentive was too narrow and some argued for an increase to up to 2% of revenue.
- Low Carbon Networks Fund (LCNF): The LCNF commenced in 2010 and allowed up to £100 million per annum for network operators to conduct projects that facilitate the transition to a low carbon future. Whereas the IFI was aimed at technical network solutions for customer benefits, the LCNF was a response to the prioritisation of electricity network innovation in order to achieve UK decarbonisation targets. £500 million was made available over a five year period, with £100 million of

[1] HoCECCC, 2010. Energy and Climate Change Committee – Second Report. The future of Britain's electricity networks. London

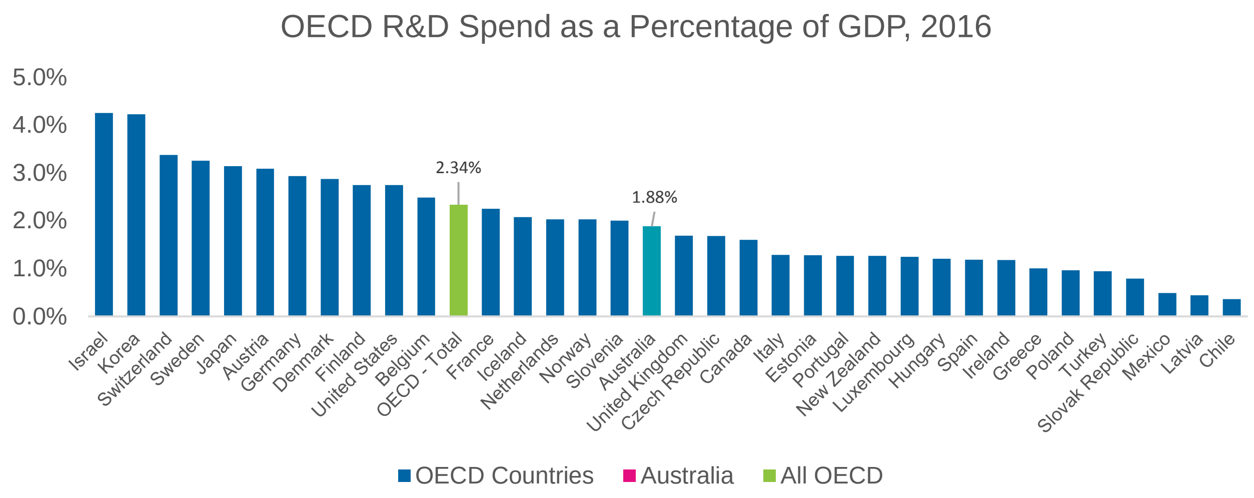
that held for discretionary funding purposes. Of the £400 million available to the networks, only £250 million was spent across 63 funded projects by March 2015[2].

- National Innovation Allowance (NIA) and National Innovation Competition (NIC). In 2015, the NIA and NIC replaced the LCNF, coinciding with the new regulatory framework, RIIO (Revenue = Incentives + Innovation + Outputs). The NIA is a fixed amount that network operators can spend on smaller projects that have a direct customer benefit. The default value is up to 0.5% of allowed revenues, or 1% where companies can demonstrate a “thought through innovation plan”[3]. The NIC is a national competition for gas and electricity networks for larger projects, with up to £70 million available per annum to electricity networks. Like the LCNF, the NIC has been underutilised. The focus of the NIA is projects that deliver a benefit to customers within the price control framework, whereas the NIC is focused on projects that deliver low carbon and environmental benefits.
- Investment Rollout Mechanism (IRM): The IRM is the third component of the current Ofgem innovation scheme. It is designed to facilitate the roll-out of proven innovations that can deliver environmental benefit and long term value for customers.

The progression of the UK innovation incentive schemes over time displays a subtle shift in motivation from technical aspects of the network, to decarbonisation and finally to a more balanced view of technical and environmental benefits. The underutilisation of the LCNF and then the NIC has led to Ofgem reducing available budgets for future periods of the NIC. Underutilisation is a reflection of the transition of innovative projects to business as usual and documented barriers to accessing the funds.

As far as stimulating innovation, regulators in Australia also face the challenge of coming off a low base. Research and Development expenditure in Australia overall is low in comparison to other OECD countries (see Figure 1). It has also declined since 2008 (see Figure 2).

***Figure 1: OECD Country R&D Expenditure, 2016***

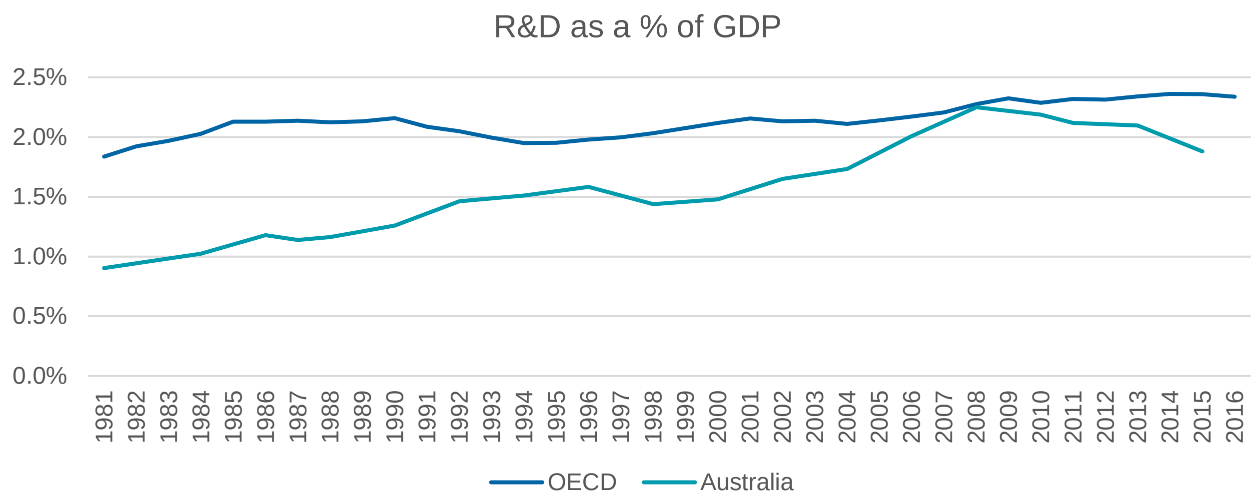



*Note: values for Australia, New Zealand and Switzerland are 2015 values, as 2016 data was not published.

[2] Frame, D.F., Bell, K., McArthur, S., 2016. A Review and Synthesis of the Outcomes from Low Carbon Networks Fund Projects. UK Energy Research Centre and Supergen HubNet, London.

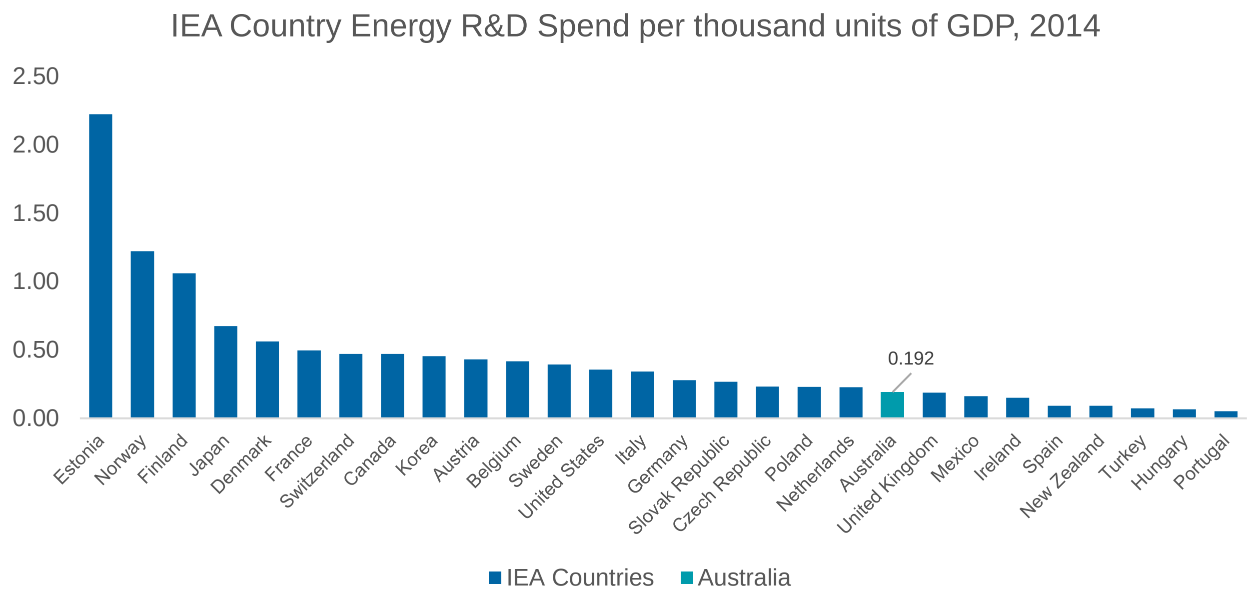
[3] Ofgem, 2013b. Price Controls Explained – Factsheet 11. Office of Gas and Electricity Markets, London

***Figure 2: R&D Expenditure, all OECD and Australia***




Australia's ranking for research and development expenditure in the energy industry is also low, as shown by 2014 data from the International Energy Agency presented in Figure 3.

***Figure 3: Energy R&D Spend per thousand units of GDP***

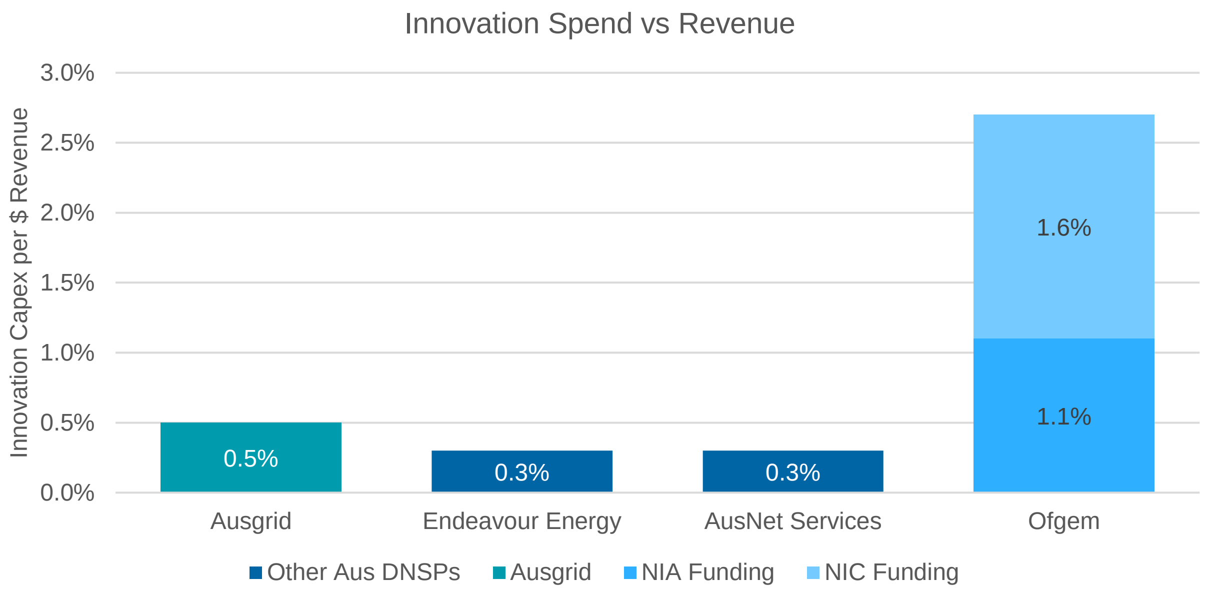



*"Most critically, despite growing recognition of the importance of energy innovation, spending on neither energy technology generally nor clean energy specifically has risen in the past four years."*

International Energy Agency, World Energy Investment 2017, July 2017

Ausgrid's proposed expenditure on network innovation in this context is not unreasonable. Comparison against selected references is shown in Figure 4.

***Figure 4: Ausgrid Innovation Spend Comparisons***




Calculation basis:

- Ausgrid: the annualised network innovation capex requested for the next period divided by 2017 revenue.
- Endeavour Energy: the annualised future network capex requested for the next period divided by 2017 revenue.
- AusNet Services: proposed annualised innovation capex from its customer forum documentation divided by 2017 revenue.
- Ofgem: The NIA and NIC funding available to electricity networks in 2016 divided by total networks 2017 revenue.

Consumer choice and network solution flexibility are not the only concerns for regulators in the current environment. Investor sentiment is closely coupled with regulatory certainty.

*"In 2016, the amount of new flexible generation capacity plus grid-scale storage that was sanctioned worldwide fell to around 130 GW – its lowest level in over a decade. This reflects weaker price signals for investment stemming from ongoing regulatory uncertainty and flawed market designs."*

*"The 6% increase in electricity network investments in 2016, with a larger role for digital technologies, supports grid modernisation and the ongoing integration of variable renewables. However, new policies and regulatory reforms are needed to strengthen market signals for investment in all forms of flexibility."*

International Energy Agency, World Energy Investment 2017, July 2017

Overall, the constraints on innovation are globally applicable and widely acknowledged, however there is little analysis on the efficacy of policy and regulatory instruments to stimulate the change required for the modern grid. One study[4] looked at the effectiveness of the UK LCNF since its inception in 2010. It found:

[4] Frame, D. et al, Innovation in regulated electricity distribution networks: A review of the effectiveness of Great Britain's Low Carbon Networks Fund, Energy Policy 118 (2018) 121–132

- The LCNF stimulated a step change in network Research Development and Demonstration (RD&D) activity.
- The LCNF also stimulated increased stakeholder engagement.
- The innovation observed was considered to be conservative and incremental in nature.
- The LCNF lacked a strategic approach to targeted learning and the reduction of uncertainty for innovation priority areas.
- Project learning outputs were contradictory and inconclusive for several innovations.

An independent evaluation[5] of the costs and benefits of the LCNF found that up until recently, the combined benefits of projects funded totalled approximately one third of the total cost, but future benefits were expected to be between 4.5 to 6.5 times the cost. To deal with the perceived lack of learnings and fragmented approach, the current UK mechanisms (NIA and NIC) mandate collaboration and dissemination of project data via a public portal.

In Australia, many industry stakeholders have argued that the current incentive schemes are too narrow to adequately facilitate the changes required. Similarly to the UK, utilisation of schemes such as DMIS has historically been low. Recently, Western Power called for a Rule change to accommodate microgrid and Standalone Power Systems solutions for economically unviable locations of the grid. The Australian Energy Market Commission (AEMC) decided against making the proposed change to the Rules.

At the time of this report, the findings of the Finkel Review of the National Electricity Market (NEM) are perhaps the most salient:

> *"By end-2018, the Australian Energy Market Commission should review and update the regulatory framework to facilitate proof-of-concept testing of innovative approaches and technologies."*
>
> Dr Alan Finkel AO, Chief Scientist, Chair of the Expert Panel, et al. Independent Review into the Future Security of the National Electricity Market, June 2017

# 5. A Framework for Evaluating Innovation Projects

It is useful to utilise a framework for the evaluation of innovation projects to ensure consistency of application and transparency of the process. We consider a suitable innovation project evaluation framework should address the merit of undertaking the project as well as the robustness of the economic analysis. These two objectives can be broken down into component elements and then into criteria, or questions, for evaluation. In selecting a framework for evaluation of the merit of innovation projects, we have considered:

- The National Electricity Objective (NEO) and National Electricity Rules (NER);

[5] Poyry, 2016. An Independent Evaluation of the LCNF – A Report to Ofgem. London.

- The Energy Networks Australia (ENA) and CSIRO Electricity Network Transformation Roadmap (which we note has been referenced by Ausgrid as a key input to its prioritisation of innovation investments[6]);
- The five areas of interest over the long to customers, identified by Ausgrid[7] through customer engagement research, namely:
    - Price management;
    - Reliability;
    - Renewables and New Energy Technology;
    - Safety;
    - Engagement.
- Evaluation frameworks from other jurisdictions.

In selecting a framework for the evaluation of the cost benefit analysis of the innovation projects, we have considered:

- The National Electricity Rules; and
- Tools from other jurisdictions, such as Ofgem's CBA Tool for environmental and innovation projects.

We have also drawn upon broader expertise within GHD and experience in:

- Business case development and economic analysis.
- Design and engineering services for electricity network assets.
- Cost estimating and benchmarking of electricity network projects and unit rates.

The links between the elements of the project analysis and three key reference documents are shown below.

***Table 1 – Links between projects and reference documents***

| Element | National Electricity Objective | National Electricity Rules | Electricity Network Transformation Roadmap |
|---|---|---|---|
| Project Need | Is it in the long term interests of consumers? | Does it align with the actions of a prudent operator? | Does it enable or facilitate progress towards the roadmap objectives and outcomes? |
| Demand forecasts and unit rates | | Are the demand forecasts and cost inputs realistic? | |
| CBA analysis | | Does it reflect the efficient costs of meeting the objectives? | |

[6] Ausgrid, *Regulatory Proposal 2019-24, Attachment 3.01 – Strategic Innovation Portfolio,* page 4

[7] Ausgrid, *Regulatory Proposal 2019-24 – Executive Summary,* page 10

We note that Ausgrid has already documented its projects against the objectives and milestones of the Electricity Network Transformation Roadmap. The framework we have adopted for assessing the Ausgrid innovation program is listed below, showing the criteria used to evaluate each element and the methods used.

***Table 2 – Innovation project evaluation criteria***

| Element | Criteria | Methods |
|---|---|---|
| Project Need | Evidence of a problem being solved<br>Evidence of innovation in the solution and/or method | Desktop review<br>Stakeholder interviews |
| Demand forecasts and unit rates | Justification of any demand forecasts<br>Justification of any unit rates | Desktop review<br>Benchmarking |
| CBA analysis | Traceability of assumptions to referenced evidence<br>Reasonableness of costs and benefits<br>Consideration of risk and uncertainty | Desktop review<br>Benchmarking<br>Sensitivity Analysis |

With respect to benefits, the Ofgem innovation governance framework requires the application of a common benefits guide for translating innovation project benefits to financial terms. The initial guide was developed by the Energy Networks Association and included mechanisms for valuing:

- Financial benefits;
- Safety benefits;
- Environmental and social benefits; and
- Carbon saving benefits.

We note that the Ausgrid analysis is mainly focused on financial, safety and social (e.g. value of customer reliability) benefits. Several of the projects have potentially significant environmental and carbon saving benefits that could also be factored into the analysis.

# 6. Assessment of Ausgrid Innovation Projects

We assessed each of the Ausgrid network innovation projects against the framework and criteria identified in section 5 of this report. The results are presented below.

## 6.1 High Voltage microgrid and fringe of grid optimisation

These two projects aim to achieve long term cost reductions for economically unviable sections of the network, whilst also reducing bushfire and safety risk. The list of CBA parameters analysed for these projects is shown below.

***Table 3 - High Voltage Microgrid and Fringe of Grid Optimisation CBA Parameters***

| Demand Forecasts | Unit Rates | Assumptions | Costs | Benefits | Risk and Uncertainty |
|---|---|---|---|---|---|
| Number of failures p.a. | Vegetation Management opex ($/km)<br>Inspection and maintenance costs ($/asset and $/km)<br>Asset replacement costs ($/asset and $/km) | Number of customers<br>Length of mains<br>Number of assets<br>Percent of failures with bushfire and safety risk | Capital cost of construction<br>Annual maintenance costs | Maintenance and vegetation management opex savings<br>Repex savings<br>Fire and safety risk savings<br>Avoided unserved energy | Sensitivity to failure rate assumption<br>Variation in construction estimates |

### 6.1.1 The problem being solved

It is widely acknowledged that the environmental conditions that contribute to the ignition and intensity of bushfires, a climate that is hotter and dryer, are becoming increasingly prevalent throughout Australia. The consequence of these conditions is an increased risk of forest fire throughout the year as represented by increases in the Forest Fire Danger Index.

*“The cost of bushfires in New South Wales alone is likely to more than double by mid-century to $100M per year. Australia experienced its hottest winter on record last year, which was made 60 times more likely due to climate change. As Australia continues to experience such unprecedented temperatures, parts of the country are seeing dangerous bushfire conditions emerge.”*

Within Ausgrid’s network, the Hunter region has historically had one of the highest incidence of bushfires, with five of ten significant bushfires in NSW since the 1970s affecting the Hunter[8] region. The use of microgrids and standalone power systems, negating the reliance on network assets through bushfire prone land, can mitigate the risk of the network being the cause of a fire or the parts of the network being destroyed by bushfires.

The dangers of relying on ageing network assets within areas of high bushfire risk were acknowledged in the Victorian Bushfire Royal Commission with one of the recommendations, recommendation 27, being the "Progressive replacement of all single-wire earth return (SWER) power lines in Victoria with aerial bundled cable, underground cabling or other technology that delivers greatly reduced bushfire risk"[9]. The funding for the implementation of this recommendation was provided by the Victorian Government, which contributed $200M.

Many of the network assets in the Hunter area were installed in the 1960s and are approaching the end of their economic life. These projects will ensure that rather than replacing like for like assets with average economic lives of 41 years[10], Ausgrid is adapting its network by using innovative solutions to both lower costs and reduce bushfire risk. In addition to these financial and safety benefits these projects will provide support for renewable energy.

### 6.1.2 Innovation

Whilst Western Australian network Horizon Power has significant experience using microgrids and standalone power systems these two projects are innovative within the NEM distribution network[11]. With the costs of renewable energy declining at a time when existing network assets are approaching the end of their economic life, the use of microgrids offers an opportunity for networks to lower both the average cost of maintaining and replacing their networks and bushfire risks.

### 6.1.3 Reasonableness of the costs and benefits

By virtue of the innovative nature of these projects, there are few publicly available examples of comparable projects from which we can draw benchmarks for Ausgrid’s proposed costs.

AusNet Services costs incurred in complying with the recommendations of the VBRC provide a useful ceiling benchmark (emphasis added):

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[8] Climate Council, Climate Change and the NSW/ACT Bushfire Threat: Update 2016, p19

[9] Page 4, https://www.aemc.gov.au/sites/default/files/content/0feb5134-9860-41e9-bd90-254f87707b8d/RuleChange-Submission-ERC0215-AusNet-Services-170718.pdf

[10] Average economic life of overhead conductors, taken from Ausgrid’s 2016/17 Category RIN

[11] AusNet has recently undertaken a microgrid project in Mooroolbark however this is not a project that is fringe of grid

> *"We note the average cost to build replacement powerlines under the Powerline Replacement Fund has been approximately **$400,000/km**."*
>
> AusNet Services – Alternative to grid-supplied network services, Response to AEMC Consultation Paper, pg4

The respective costs per km for the HV microgrid and the fringe of grid optimisation projects proposed by Ausgrid are $277,778 and $39,024.

#### 6.1.3.1 Demand forecasts

Ausgrid has assumed HV feeder failure rates of 20 per annum and 11 per annum for the microgrid and fringe of grid projects respectively for the base reference case. These rates are based on outage management system historical averages, and therefore a reasonable basis for the forecast.

#### 6.1.3.2 Unit rates

The table below uses unit cost comparisons between Ausgrid's avoided capex associated with this project and the unit costs of replacement for other networks. Data has been taken from the Category RINs and uses a four year average.

***Table 4 – Unit costs of assets replaced***

| | Ausgrid | AusNet | Endeavour | Essential | Powercor | Ergon |
|---|---|---|---|---|---|---|
| Transformers | $60,000 | Comparison relies on identification of transformer rating which is not available | | | | |
| Service Wires | $500 | $1,721 | $948 | $1,315 | $49,223 | $1,739 |
| Poles | $11,000 | $12,958 | $10,234 | $5,354 | $11,338 | $7,425 |
| Steel lines | $37,000 | $55,175 | $28,894 | $37,497 | $19,654 | $68,804 |
| Air Break Switch | $12,000 | No Data Available | | | | |
| **Comparison cost**[12] | **$6,033,159** | **$7,978,870** | **$5,325,172** | **$4,298,361** | **$11,142,634** | **$7,008,798** |

Even without values for the transformer and air break switch, the total comparison cost is reasonable within the context of other network values with Ausgrid's estimates the 3rd lowest of the six networks used to provide a comparison[13].

Approximately half the opex benefits associated with this project are from reduced vegetation management obligations. Endeavour Energy's vegetation management expenditure in rural parts of its network have been used to provide a comparison to Ausgrid's proposed benefits of $2,350 per km. Endeavour has been used as a comparison point for two reasons:

[12] Have multiplied Ausgrid's proposed number of assets replaced by the unit costs – Only service wires, poles and steel lines used at this point

[13] These networks have been used as comparisons because they have network assets in rural areas, Ausgrid's is proposing the implementation of these two projects will occur in a rural location.

1) Endeavour Energy publishes vegetation management costs by area in their Category RINs, and
2) The area proposed by Ausgrid for these projects (the Hunter region) will most closely resemble the rural areas of Endeavour's network with respect to climate and legislated clearance requirements which are state based[14].

Endeavour Energy's vegetation management per km for areas of its network with predominantly rural spans[15] is illustrated in Table 5 below, Ausgrid's proposed benefits have also been included.

***Table 5 - Endeavour Energy Vegetation Management Costs***

| Area | Trees per km | Vegetation Management per km |
|---|---|---|
| Shellharbour | 20 | $2,729 |
| Nowra/Ulladulla | 15 | $2,379 |
| **Ausgrid** | | **$2,350** |
| Bowral (Mossvale) | 25 | $2,271 |
| Windsor | 51 | $2,267 |
| Narellan/Picton | 56 | $1,801 |
| Bowenfels/Kandos | 9 | $987 |

The table suggests that Ausgrid's proposed vegetation management benefits, whilst within the range of Endeavour Energy's costs, are at the higher end of the range.

Beyond the benefits of avoided vegetation management costs, Ausgrid has indicated a benefit of $2,438 per km from routine and non-routine maintenance that will be avoided by the removal of network assets for both the HV Grid and fringe of grid optimisation projects. This figure has been tested against Endeavour Energy's historic maintenance expenditure per km.

Endeavour Energy has been used as the comparison network as it is the closest comparator with respect to the exogenous factors used by the AER in its opex benchmarking analysis. These factors include taxes and levies, severe storms, cyclones, termite exposure, WHS regulations and sub-transmission and license conditions. Of these factors, an adjustment has been made to account for Endeavour Energy's sub transmission network[16], these values have been adjusted using the assumption, relied on in Ausgrid's last regulatory determination, that sub-transmission assets incur twice the opex costs per km as distribution network assets below 33kV.

[14] Essential Energy's vegetation management expenditure has been made unavailable in their 2017 Category RIN

[15] Greater than 50% of vegetation spans in an area classified as rural

[16] This is to adjust for the increased maintenance costs associated with assets greater than 33kV. Ausgrid's assets used in the HV Grid and fringe of grid optimisation are below this threshold and therefore no adjustment has been made for Ausgrid's maintenance estimates.

Endeavour's adjusted maintenance per km has been calculated as follows:

> (Distribution OH km * **Distribution maintenance per km** + Sub-transmission OH km * 2***Distribution maintenance per km**) / (Distribution OH km + Sub-transmission OH km) = Maintenance per km
>
> Rearranged to isolate maintenance of distribution assets per km gives:
>
> **Distribution maintenance per km** = (Maintenance per km*(Distribution OH km + Sub-transmission OH km))/(2* Sub-transmission OH km + Distribution OH km)

Table 6 below details Endeavour Energy's maintenance per km over the past four years[17] and the adjusted maintenance per km value that takes into account the sub-transmission assets in Endeavour's network. Ausgrid has indicated that distribution assets are to be replaced within the HV grid and fringe of grid optimisation projects so no adjustment has been made for the estimated maintenance cost benefit per km[18].

***Table 6: Endeavour Energy maintenance per km over time ($2017)***

| | 2014 | 2015 | 2016 | 2017 | Average |
|---|---|---|---|---|---|
| Maintenance (exc UG assets) | $59,455,797 | $51,355,550 | $55,315,919 | $61,759,140 | **$56,971,601** |
| Overhead line length (km) | 23,387 | 23,369 | 23,295 | 23,227 | **23,319** |
| OH maintenance / km | $2,542 | $2,198 | $2,375 | $2,659 | **$2,443** |
| Adjusted OH maintenance per km | $2,234 | $1,930 | $2,086 | $2,329 | **$2,145** |
| **Ausgrid proposed maintenance per km** | | | | | **$2,438** |

Incorporating Endeavour Energy's average vegetation management and maintenance costs per km as benchmark reference points give values of $2,289 and $2,145 per km respectively. These are compared with Ausgrid's proposed opex benefits in Table 7 below.

***Table 7: Opex benefits comparison***

| Benefit | HV Microgrid | Fringe of Grid Optimisation | Reference Point |
|---|---|---|---|
| Vegetation management per km avoided | $2,350 | $2,350 | $2,289 |
| Maintenance per km avoided | $2,438 | $1,433 | $2,145 |

[17] Four years has been used because the Category RIN data is available from 2013/14

[18] Data has been taken from Endeavour Energy's Category RINs with underground maintenance and underground line length excluded

The difference in avoided maintenance per km between the two projects is because the fringe of grid optimisation will replace SWER lines which Ausgrid have estimated to require half the maintenance of other distribution voltages.

These comparisons indicate that the opex and capex unit costs proposed in the calculation of the benefits for the HV Microgrid and Fringe of grid optimisations are broadly consistent with unit costs published in the Category RINs of comparable networks.

#### 6.1.3.3 Assumptions

[redacted]

Length of mains and the number of assets: Similarly to the number of customers, the length of mains and assets that will be removed through the implementation of these projects has been sourced from Ausgrid's asset management systems on the parts of the networks that have been identified as suitable for these two projects. Therefore this information is likely to be correct.

Percent of failures with bushfire and safety risk: The other assumptions made in the business cases for these two projects are the proportion of failures with bushfire and safety risk. Safety risk has been estimated to be 0.10% - this means that for every feeder failure, there is a 1 in 1,000 chance of someone being electrocuted. The probability of electrocution is a value that will depend on a number of factors such as population density, installed protection systems, location of the assets and barriers installed preventing the public interacting with network assets. Energy Safe Victoria's *2018 Safety performance report* indicated that 3 electrocution incidents occurred throughout 2017, all on Jemena's network. Taking the number of feeder outages reported 3,571 gives a 1 in 1,190 chance of electrocution. No similar incidents were reported for the other Victorian networks. We note that whilst a 1 in 1,000 chance may be considered high relative to the Victorian benchmarks, the respective uplift in NPV for safety improvements are approximately $19,000 (fringe of grid) and $25,000 (HV Microgrid) which can be considered immaterial.

The assumed probability of a feeder failure causing a fire has been taken from historic data. A probability of asset failure causing a fire has been calculated as 5.4% or 1 event in every 18 incidents. Given this information has been sourced from 2017 incident data in the Central Coast and Hunter Regions of Ausgrid's network this information appears a reasonable basis for estimation. The bushfire probability and associated costs are significant inputs into the proposed benefits of these projects with respective NPV increases of $15M (fringe of grid) and $20M (HV microgrid) over the 17 year period used in the business case. This is a significant value that has the largest impact of the economic feasibility on both these projects. The methodology used by Ausgrid to calculate the costs of bushfires is outlined below in the benefits section.

#### 6.1.3.4 Costs

It is difficult to assess the capital construction cost and annual maintenance cost assumptions prior to the selection of a site and detailed project estimates.

[19] At the time of writing the locations of these projects is confidential

#### 6.1.3.5 Benefits

The unit rates associated with the repex and maintenance costs of the assets to be removed were identified as reasonable in section 6.1.3.2, therefore the value of the benefits associated with these two elements are considered reasonable. The fire risk savings equate to around $2.1M p.a for the HV microgrid project and $2.4M[20] p.a for the fringe of grid optimisation project. This has been calculated as follows:

Value of removed bushfire risk = Forecast number of feeder failures x Probability of bushfire from failure x Bushfire cost

The first two parameters (number of feeder failure and probability of bushfire caused by asset failure) have been discussed above and found to be reasonable. Ausgrid's estimate of bushfire cost is $3.9M and has been informed by the bushfire costs estimated by EvoEnergy and CutlerMerz[21] .

| Severity | Cost of Consequence | Grossly DF | Probability of Severity | Value |
|---|---|---|---|---|
| Severe | $66,000,000 | 10.0 | 0.005 | $3,300,000 |
| Major | $6,600,000 | 8.0 | 0.010 | $528,000 |
| Moderate | $660,000 | 6.0 | 0.020 | $79,200 |
| Minor | $66,000 | 4.0 | 0.100 | $26,400 |
| Insignificant | $6,600 | 2.0 | 0.865 | $11,418 |
| **Value used** | | | | **$3,945,018** |

The costs of a bushfire at each severity have been calculated from historic bushfire events and are taken directly from EvoEnergy's Draft Determination. The probability of severity details the probability of bushfire severity given a fire has been caused. For example, if a fire starts on Ausgrid's network there is a 0.5% chance that it will be severe. DF refers to disproportionality factors and refers to the weight an organisation puts on each bushfire risk.

*"Guidance from the Health Safety Executive (UK) suggests that a DF between 2 and 10 can be used. Higher values are used for situations where extensive harm is possible if the risk event were to occur."*

Cutler Merz – Consequence valuation December 2017, pg 7

Ausgrid's bushfire risk valuations have been calculated using historic bushfire costs and industry accepted probabilities of occurrence and disproportionality factors, we therefore consider these to provide a reasonable estimate of the value of reduced bushfire risk for these two projects. It is also worth noting that these values are based on historic bushfire costs and risks. As mentioned in the introduction to this section, the Climate Council predicts that the costs of bushfires in NSW will double by 2050 as a consequence of

[20] This values are different as each project will remove a different quantity of assets covering different network areas

[21] EvoEnergy Draft Proposal, Appendix 5.2 Cutler Merz Consequence Valuation

increasing likelihood and severity of bushfires. In this context, when using a bushfire safety value that covers a 50 year investment, Ausgrid's value of bushfire risk should be viewed as a lower bound.

#### 6.1.3.6 Risk and Uncertainty

The main sensitivities of the CBA analysis for these projects is the failure rate assumption and the construction cost estimates, given the value of these projects. For each project, we examined:

1. The point at which the project benefit to cost ratio would fall below 1.0 with changing assumptions of failure rates; and
2. The point at which the project benefit to cost ratio would fall below 1.0 with changing estimates of construction costs.

The results of this sensitivity analysis are below.

***Table 8: Sensitivity Analysis for Microgrid and Fringe of Grid Projects***

| Project | Variable | Ausgrid Assumption | BCR Tipping Point |
|---|---|---|---|
| HV Microgrid | Failure Rate | 20 HV feeder outages | 14 HV feeder outages |
| HV Microgrid | Capital Cost NPV | $19.4 million | $26.3 million |
| Fringe of Grid | Failure Rate | 11 HV feeder outages | 1.6 HV feeder outages |
| Fringe of Grid | Capital Cost NPV | $4.5 million | $17.7 million |

As shown, the fringe of grid optimisation project has much greater margin of safety in its CBA analysis based on the input parameters tested. However we believe that the published HV microgrid benefits are understated as they do not include a financial evaluation of the carbon offset opportunities.

## 6.2 Network insights program

This project aims to deliver opex efficiencies from a reduction in site visits by Ausgrid's field staff. This will be enabled through the remote monitoring of asset utilisation and network state switching on existing network equipment for planned works and emergency management. Other benefits identified through this project are improved distributed energy hosting capacity and longer term reductions in augmentation capex through increased utilisation of the existing network. The list of CBA parameters analysed for this project are shown below.

***Table 9 – Network Insights Program CBA Parameters***

| Demand Forecasts | Unit Rates | Assumptions | Costs | Benefits | Risk and Uncertainty |
|---|---|---|---|---|---|
| Not applicable | Manual switching cost | Number of devices | Capital cost of devices | Capex deferral<br>Manual switching opex | Value of Customer Reliability |

| Demand Forecasts | Unit Rates | Assumptions | Costs | Benefits | Risk and Uncertainty |
|---|---|---|---|---|---|
| | Avoided MDI reads<br>Other avoided site visit rates | | Ongoing maintenance | Avoided site visits<br>Reduction in unserved energy | Estimation of minutes saved |

### 6.2.1 The problem being solved

With the proliferation of distributed energy resources it is becoming increasingly necessary that a network has visibility of its low voltage network. Access to this information will allow Ausgrid to identify constrained areas of their network and implement appropriate network or non-network responses. Greater visibility of network utilisation allows Ausgrid to better manage the maintenance, operation and augmentation of its network in much the same way Victorian networks have benefited from having access to customer demand data due to the mandated smart meter rollout in Victoria. A higher visibility of the network will also allow for reductions in fault restoration times as the location of network faults are more accurately identified.

### 6.2.2 Innovation

Whilst the technology being used by Ausgrid could not be considered innovative the program will enable innovation by providing information below the zone substation level on network utilisation. Our understanding is that this data will be made publicly available which will allow greater visibility of Ausgrid's network for customers, non-network participants and researchers. For example, UTS maintains network opportunity maps that show areas of the NEM in which demand management, battery storage and renewable energy would provide the most benefit to the grid. The prerequisite to innovative solutions is the availability of network data, the Network insights program will enable this data to be collected at a more granular level than is currently possible. AusNet Services customer research has indicated that of the 15 proposed innovation projects from 2021-25 there are three with high support from customers[22], one of which is the *Market facing data and information platform trial*. This suggests that access to more useful data is something that customers' value.

### 6.2.3 Reasonableness of the costs and benefits

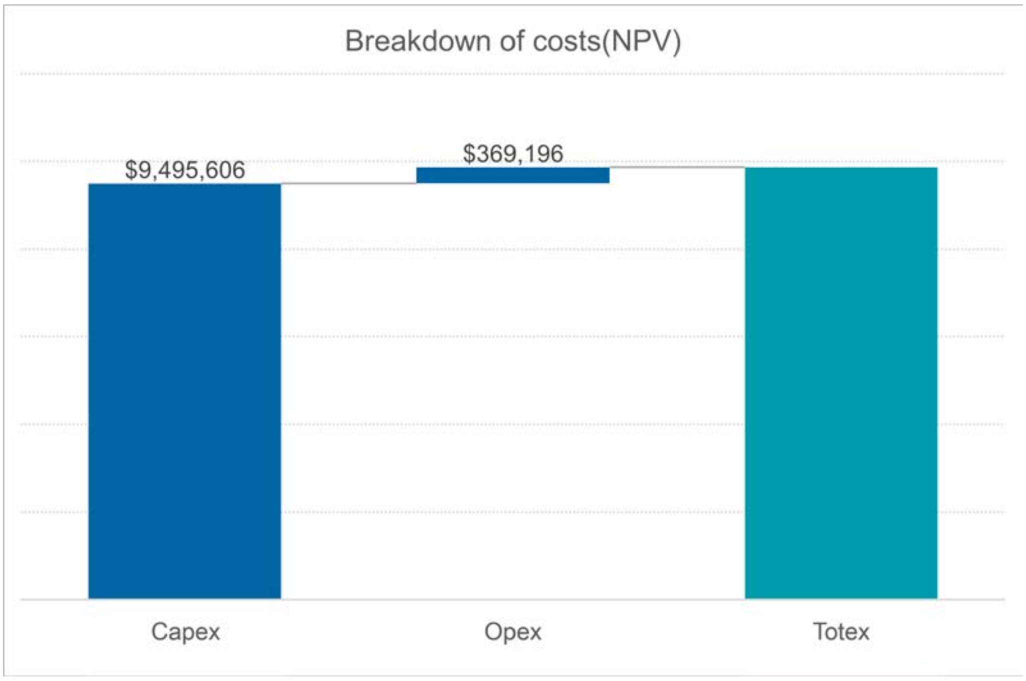
#### 6.2.3.1 Costs

The estimated program costs are predominantly the capital expenditure associated with the upgrading or retrofitting of 1,140 distribution substations. The cost estimates are based on CPI escalation of figures from a 2013 trial. We consider this a sound basis for input costs for the CBA for this project.

The opex costs are negligible (NPV of ten years maintenance is $324 for a single device), the viability of the business case is therefore whether the benefits attributed to each remotely controlled distribution substation monitoring are greater than $8,653 per installed device.

[22] AusNet Services, Innovation expenditure – negotiating position for the Customer Forum, Page 7

*Figure 5: NPV of Costs for Network Insights Program*

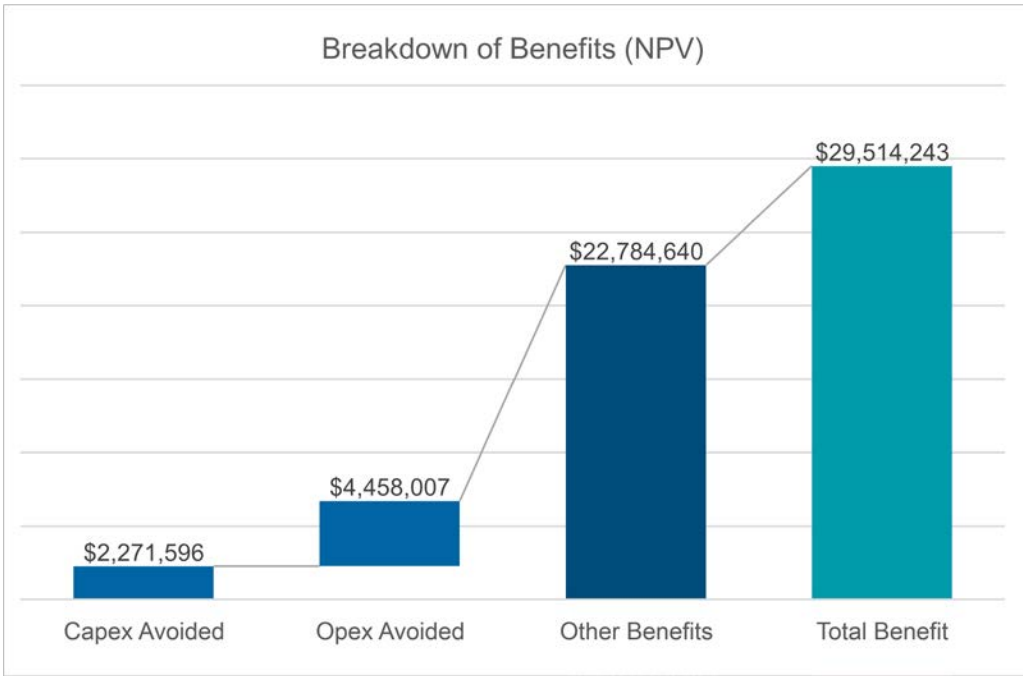



#### 6.2.3.2 Benefits

The table below highlights the three different sources of benefit from implementing the Network Insights Program. These are the capex deferred as a result of greater network utilisation[23], the opex avoided from manual switching, manual demand reads, load and voltage surveys and the value of improved reliability. The improvements in reliability are due to quicker restoration times associated with remote switching rather than having to manually operate switchgear, these quicker restoration times mean a reduction in unserved energy.

[23] With a greater understanding of the supply / demand balance at 1,140 distribution substations Ausgrid will be able to tolerate greater levels of demand utilisation

*Figure 6: NPV of Benefits for Network Insights Program*




The breakdown of benefits at a per substation level are detailed below. The table shows that the combined NPV of the estimated benefits per distribution substation are $2 relative to a cost per substation of $8,653.

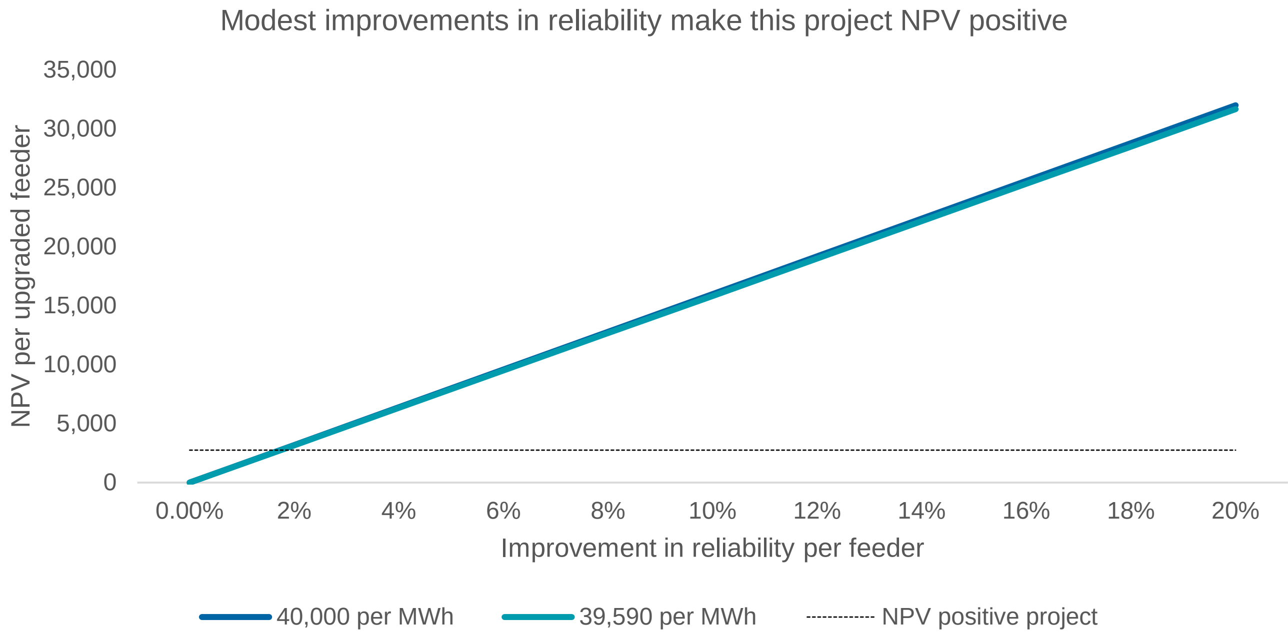
*Table 10: NPV of Benefits vs Costs per Substation*

| Benefit per distribution upgraded substation (NPV) | | | | Cost per distribution substation (NPV) |
|---|---|---|---|---|
| Opex | Capex | Reliability | Total benefit | Total cost |
| $3,911 | $1,993 | $19,990 | $25,894 | $8,653 |

#### 6.2.3.3 Risk and Uncertainty

Table 10 indicates it is predominantly improvements in reliability that support the implementation of the Network Insights Program with an assumed benefit of $22,489 per installation over the ten year period. The assumptions underpinning these reliability benefits are a value of customer reliability of $40,000 per MWh and an average reduction in unserved energy of 12.5% per interruption. Whilst this reduction is a combination of an expected reduction in the number customers affected by a sustained outage and the duration to restore supply, it is the equivalent of an outage requiring 30 minutes to rectify being rectified in 26.25 minutes if remote switching and fault detection were available. To test the sensitivity of the Network Insights Program to changes in these assumptions we have used varying assumptions around the improvement in reliability and Ausgrid's value of customer reliability used by the AER in their Annual Benchmarking Report ($39,590 per MWh). These results are displayed below and show that the Network Insights Program becomes NPV positive for reductions in outages greater than 1.65% (using a VCR of $40,000 per MWh) and 1.7% (using the AER's VCR of $39,590).

*Figure 7: Sensitivity to VCR value and reduction in outage assumptions*




Looking at 1.65% reduction in outage time as a reference hurdle point then, we considered evidence from other similar projects. A U.S. Department of Energy report in 2014[24] found that fault location, isolation and service restoration technologies had the capacity to reduce customer minutes of interruption by outage time by up to 47% where remote switching was applicable and 53% where auto switching was possible. Whilst the network insights program is only one component of a system that would facilitate these benefits, there is clearly scope to realise at least a 1.5% reduction in outage time through the Ausgrid network insights program.

Ausgrid's proposed costs and benefits appear reasonable for the Network Insights Program, particularly if the program allows for greater transparency of the utilisation of Ausgrid's low voltage network. In addition, this project will incur capex over five years as distribution substations are being upgraded with the technology. This allows Ausgrid's Network Innovation Advisory Committee (NIAC) to review progress early on in the program and intervene if the costs and benefits associated with this project are different to those estimated.

## 6.3 Advanced Voltage Regulation

The advanced voltage regulation program will incorporate voltage regulation technology to mitigate sites on Ausgrid's network where voltage issues are preventing distributed generation resources access to the network. The list of CBA parameters analysed for this project are shown below.

[24] U.S. Department of Energy, 2014, Fault Location, Isolation and Service Restoration Technologies Reduce Outage Impact and Duration.

*Table 11 – Advanced Voltage Regulation CBA Parameters*

| Demand Forecasts | Unit Rates | Assumptions | Costs | Benefits | Risk and Uncertainty |
|---|---|---|---|---|---|
| Sites with voltage issues | Cost of STATCOM, Average cost of distributor upgrade | Customers per site impacted. Proportion of sites where a STATCOM is the efficient solution | STATCOM capex | Avoided capex expenditure | Sites impacted with voltage issues |

### 6.3.1 The problem being solved

At the current levels of solar penetration Ausgrid is experiencing voltage issues at a number of sites. The graphs below (Figure 9 and Figure 10) highlight the forecast number and size of solar panels on Ausgrid's network over the next 30 years. Whilst there are significant increases forecast (greater than 400% over 30 years), the next five years alone will see an increase of 61% in the number of DER customers on Ausgrid's network.

***Figure 8: DER Customer Forecast***

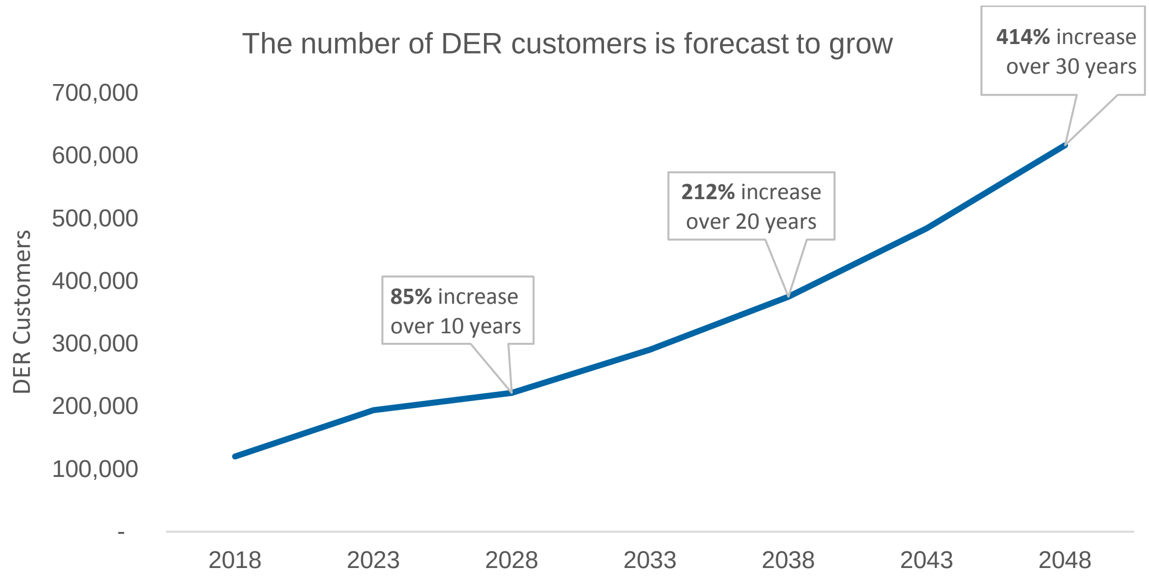
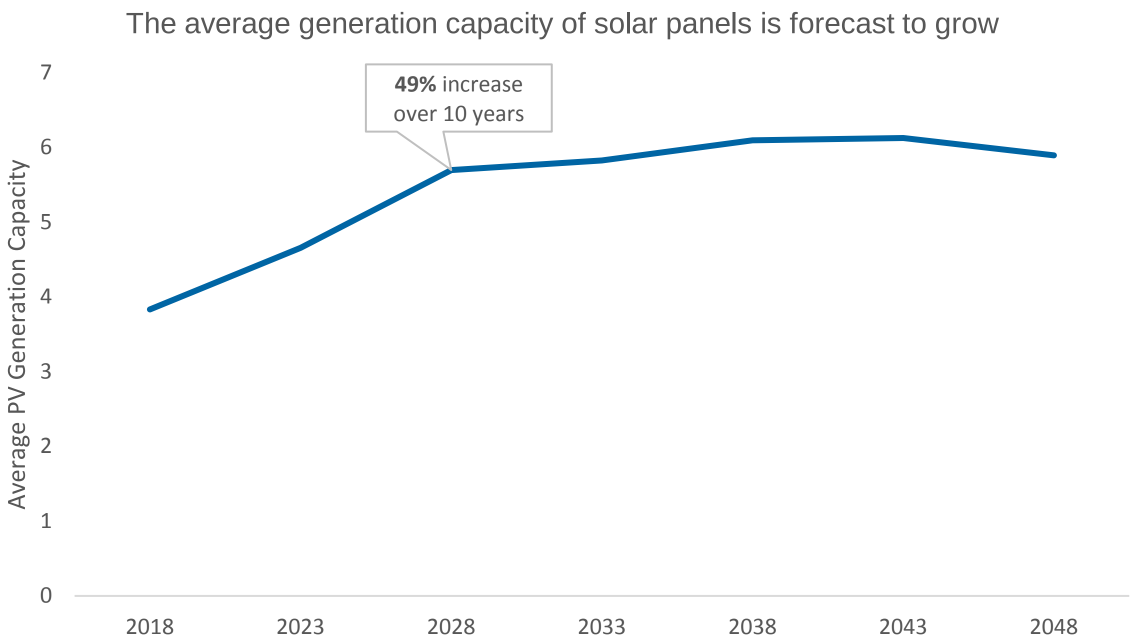


*Figure 9: Average PV Generation Capacity Forecast*




Whilst thirty year forecasts of a technology that is changing as rapidly as solar panels are difficult to make what is indisputable is that the number of customers with solar panels is increasing and will continue to do so and the generating capacity of the solar panels these customers are installing are increasing and will continue to do so.

With increases in both the volume and generation capacity of distributed generation the number of sites on Ausgrid's network with voltage issues are also forecast to increase as increasing volumes of electricity are generated on residential rooftops and fed into Ausgrid's network.

### 6.3.2 Innovation

The use of STATCOMs to regulate network voltages as an alternative to traditional investment can be considered an innovative solution. Other networks that have recently begun installing or are planning to install STATCOM's include Ergon Energy and Endeavour Energy. Whilst the technology itself is not innovative, the integration of voltage regulation technology within Ausgrid's network and under different network conditions is not yet understood. This project will assess the viability of this voltage regulation technology to avoid the need for Ausgrid to augment its network with traditional distribution substation upgrades. In the context of Ausgrid's guiding principles for innovation, this project solves a specific problem and promotes the acceleration of cost effective decarbonisation.

### 6.3.3 Reasonableness of the costs and benefits

#### 6.3.3.1 Demand forecasts

Ausgrid has based forecasts of sites with voltage issues on forecasts of solar penetration provided by Energeia. In Endeavour Energy's most recent Distribution Annual Planning Report the issue of increasing solar generation and voltage issues was also raised:

*"In recent years, the proliferation of solar PV has reduced daytime demand significantly and in some cases reversed power flows which has contributed to voltages outside of the standard range. As a result, complaints of high voltage have now become more significant than complaints of low voltage"*

Endeavour Energy 2017 Distribution Annual Planning Report, pg 27

Ausgrid's staff have indicated through interviews that the experience of Endeavour Energy is mirrored in Ausgrid's network. That is, as the number of rooftops with solar generation have increased so too have high voltage complaints.

Ausgrid's forecast assumes that as solar penetration increases, so too will the number of sites with voltage issues. Of these sites with voltage issues, Ausgrid estimates that STATCOM's will be the most efficient solution 10% of the time. Ausgrid has assumed a proportional relationship between each of these factors (i.e. solar penetration in 2029 is forecast to be 280% greater than in 2019 and therefore the number of sites with voltage issues will be 280% greater).

This appears to be a reasonable estimate and may in fact be conservative as it assumes a relatively constant relationship between the two. For example, if the number of customer sites is skewed towards values where voltage levels are at the limit, then a small increase in solar penetration would be expected to have a greater impact on voltage issues.

#### 6.3.3.2 Unit rates

[redacted]

#### 6.3.3.3 Assumptions

Ausgrid has used an extrapolated forecast of sites affected from a baseline estimate of the 2018 value. We find this to be a reasonable basis for estimation of future scope of the project. A fixed assumption of 10% of sites being suitable for a STATCOM solution is also used. This is difficult to evaluate, but we do not consider it unreasonable, as studies have shown[25] that the proportion of sites where a STATCOM solution is viable may be higher that the assumed 10%.

#### 6.3.3.4 Costs

By way of reference, Endeavour Energy has proposed a budget of $580k for the installation of four pole mounted LV STATCOMs on their network[26]. Ausgrid are proposing a budget of $3.1M (NPV of $2.8M) for up to 21 sites, which appears reasonable in comparison (particularly given the mix of LV and the more expensive HV solutions in the Ausgrid project).

#### 6.3.3.5 Benefits

The NPV of Ausgrid's proposed benefits is $4.8M which means the project is NPV positive by $2M. The benefits accrued are associated with the avoidance of distributor and distribution substation upgrades over the period. The proposed benefits are calculated for each year as the difference between a STATCOM cost

[25] Dean Condon, Don McPhail & David Ingram (2016): "Application of low voltage statcom to correct voltage issues caused by inverter energy systems", 26th Australasian Universities Power Engineering Conference (AUPEC 2016), Brisbane, Queensland, 25-28 September.

[26] Page 53 Endeavour Energy Future Network Strategy – March 2018

and the cost of a traditional upgrade ($48,000) multiplied by the number of sites that are forecast to have voltage issues. Whilst Ausgrid has estimated the benefits associated with avoided network upgrades there are also likely to be external benefits to customers. This is because in the do nothing case there would be customers that would be unable to access the network at certain times when high network voltages force solar panel inverters to trip out.

#### 6.3.3.6 Risk and Uncertainty

The key risk associated with the voltage regulation program is that the number of sites with voltage issues, and therefore requiring intervention, do not eventuate. The impact of this would be that the estimated cost to rectify these issues ($3.1M) are overstated. This risk is somewhat mitigated by the oversight of the Network Innovation Advisory Committee, a committee comprised of representatives of Ausgrid and the Ausgrid Consumer Consultative Committee.

*"Where it is agreed that capital expenditure overseen by the NIAC can be deferred or reduced in scope, Ausgrid will not receive any potential reward under the CESS."*

Source to be added (Currently in Draft Status)

The inclusion of this project within the control of the NIAC is a useful risk mitigation instrument on the behalf of customers as it allows for Ausgrid to plan for the future based on current estimates but adapt as circumstances invariably change. For example, if home battery prices fall quicker than anticipated resulting in greater storage capacity at the household level and reducing the number of sites with voltage issues, Ausgrid can reconsider the scope of this project. As indicated in the quote above, projects within the remit of the NIAC will not be subject to the CESS. Similarly, to the Network Insights Program, this is a project with a positive NPV ($1.9M) and reasonable estimates of costs and benefits that will incur costs over time as sites are addressed. This allows the NIAC to monitor the current estimates over time and change the project scope as required.

## 6.4 Grid Battery Trials

This project aims to develop grid batteries as a means of extracting value from a full range of capabilities at both the network level and customer accessibility side of the technology. A grid battery provides a viable solution for capex deferral at both the distribution level and sub transmission level. The project will also explore opportunities to utilise the installed battery to facilitate energy trading of DER resources for those customers who are unable to install their own DER or battery systems, promoting fairness with respect to network access for Ausgrid's customers. These customers would be able to access the battery for their own solar assets, which facilitates system subsidisation and gives customers access to storage technology at a much lower cost than installing their own battery assets. Third party operators may also access the asset in future for selected delivery of market services. Ausgrid has proposed that the batteries may be relocatable, allowing re-use at new sites once installed, and can provide benefits if operated in islanded mode to maintain supply to customers affected by major feeder outages. We note that the full purpose of this project much wider than augex deferral, however at this point in time Ausgrid has limited its CBA to deferral benefits only. In this respect, the NPV and BCR are conservative and a full assessment of the benefits at the business case stage will increase the financial attractiveness of the project. The list of CBA parameters analysed for this project are shown below.

*Table 12 – Grid Battery Trials CBA Parameters*

| Demand Forecasts | Unit Rates | Assumptions | Costs | Benefits | Risk and Uncertainty |
|---|---|---|---|---|---|
| None applicable | Relocation costs<br>Typical zone substation costs | Augex deferral of one year<br>Relocation every three years | Battery purchase and installation<br>Annual maintenance costs | Deferral of capex<br>Avoided unserved energy | Deferral period and relocation assumptions<br>Feeder failure rate |

### 6.4.1 The problem being solved

The declining cost of battery technology combined with the increase in distributed energy uptake means that in parts of the network augmentation can be deferred with the use of grid batteries. Research suggests that whilst the cost of residential batteries have decreased significantly, and will continue to do so, the payback period is still generally greater than the warranty.

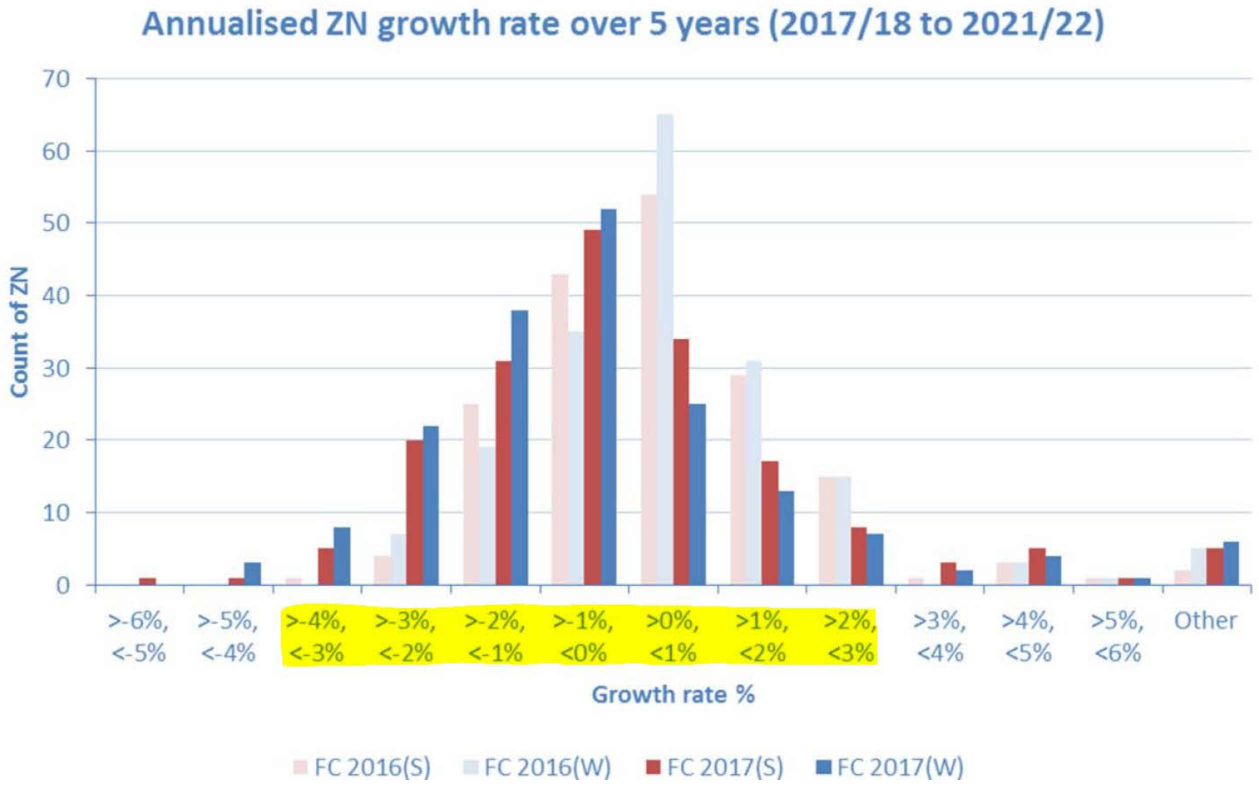
*"According to CEC, the cost of lithium ion batteries has fallen by 80% since 2010 and is expected to halve again within seven years.[27]….but for now solar researchers, industry analysts and consumer groups all agree: unlike solar panels, it doesn't quite make economic sense for the average householder to invest in batteries"*

The ability to rely on network batteries in circumstances that in the past may have initiated a substation installation or upgrade is effectively an insurance policy that allows Ausgrid to delay augmentation. Grid batteries provide Ausgrid with the opportunity to wait and see if demand in an area is rising to the point network augmentation and the introduction to the network of a 50 year asset is required or whether the impact of solar, batteries and other physical and demographic factors influencing peak demand at the customer level will mitigate the need for an upgrade. The graph in Figure 11 below, taken from Ausgrid's 2017 Electricity Demand Forecast Report, highlights the benefits of having flexibility of capacity.

The dark blue and red bars indicate estimates of five year summer and winter growth made in 2017 whilst the lighter bars indicate forecasts made in 2016. The highlighted columns indicate that the number of zone substations with a growth rate above zero (increasing utilisation) has fallen significantly whilst the number of zone substations with demand forecast to decline has increased. Taking the blue bars which forecast growth in winter maximum demand as an example, in the 2016 forecast there were approximately 65 substations that were forecast to have growth between 0-1% per annum, in 2017 this forecast was now approximately 25. By contrast, the number zone substations that had estimates of a decline in annual growth of between 0-1% has increased between 2016 and 2017 from 35 to 52 respectively. These results shows the significant uncertainty that exits in forecasting future electricity growth in the network, particularly in the current economic and political climate where electricity prices and climate change are reported on daily and are therefore constantly front of mind for Ausgrid's customers.

[27] " https://www.abc.net.au/news/science/2018-08-16/does-it-make-sense-to-buy-solar-batteries-or-should-i-wait/10119900

*Figure 10: Zone Substation Growth Forecasts*




### 6.4.2 Innovation

The use of network battery storage to defer network augmentation is not a unique approach (Endeavour Endeavour, SA Power, Ergon Energy, CitiPower and Western Power have all used or are currently using this approach) however this Ausgrid proposal unlocks broader customer accessibility benefits that customers have indicated that they want, and will come to expect from network service providers. Innovative energy management solutions that give customers access, choice and flexibility in the management and trading of electricity from both their own assets and shared assets have proven to be highly successful, for example the Brooklyn, NY community powered microgrid[28].

### 6.4.3 Reasonableness of the costs and benefits

The NPV of Ausgrid's reported costs and benefits for this project are included in the table below. The program NPV is based on an assumption that the battery will defer augmentation for one year and is relocated every three years. Over the planning period, the BCR only just clears the parity hurdle, but as mentioned earlier, the full value of customer benefits has not yet been included in the analysis.

*Table 13 – Grid Battery Trials CBA NPV*

| CBA Component | Net Present Value |
|---|---|
| Opex cost (Battery maintenance) | $53,640 |

[28] https://www.brooklyn.energy/

| CBA Component | Net Present Value |
|---|---|
| Capex cost (Installation and relocation) | $2,708,502 |
| *Total Cost:* | $2,762,142 |
| Capex benefit (Deferred augex) | $2,256,200 |
| Other benefit (Improved reliability) | $543,103 |
| *Total Benefit:* | $2,896,822 |
| **Program NPV (2020-29):** | **$37,161** |

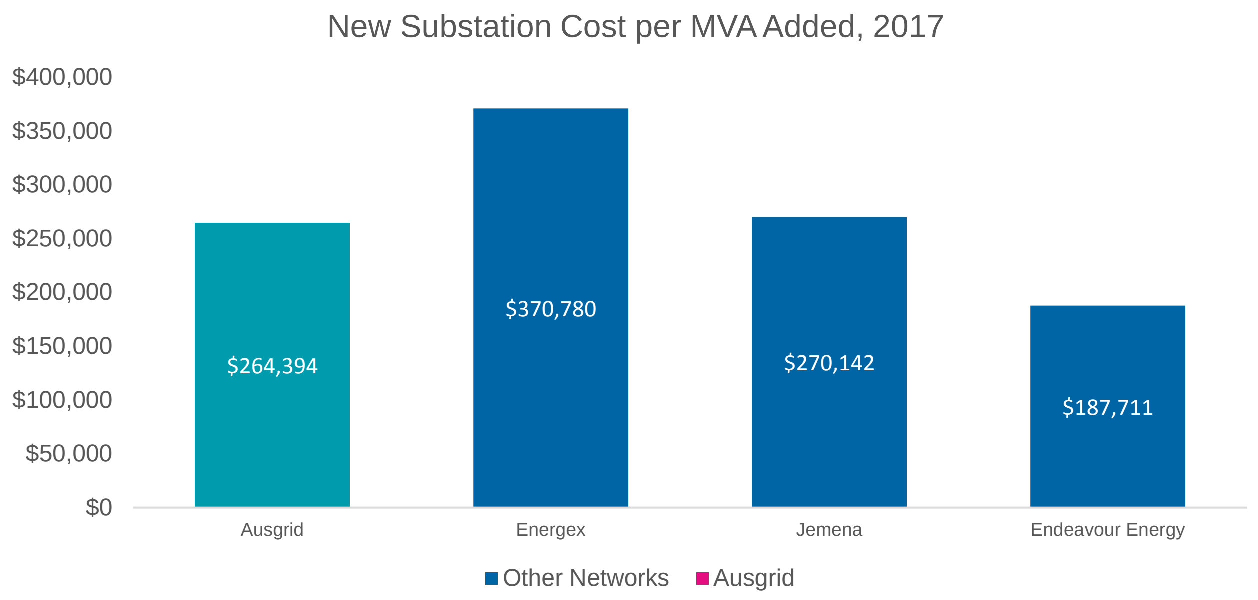
#### 6.4.3.1 Demand forecasts

There are no demand forecasts applicable to this project.

#### 6.4.3.2 Unit rates

The relocation costs of $600,000 appear reasonable given the estimate of installation of $500,000. The typical zone substation cost is the primary input into the capex deferral benefit assumption. The average cost of new substation projects in the Ausgrid 2017 Category RIN is $24.5 million, just below the assumed $25 million in the project CBA. This can be compared to other networks, but the variation in costs is significant, driven by the input side voltage (132kV for many of Ausgrid's substations) and the MVA added for the new substation. To benchmark the unit cost of a new substation, therefore, we looked at cost per MVA added for a number of urban networks in 2017 as shown in Figure 12 below (CitiPower and United Energy had no new substation projects in this period). Based on this analysis, we do not find the Ausgrid assumption unreasonable.

***Figure 11: Cost per MVA for New Substation Establishment, 2017***




### 6.4.3.3 Assumptions

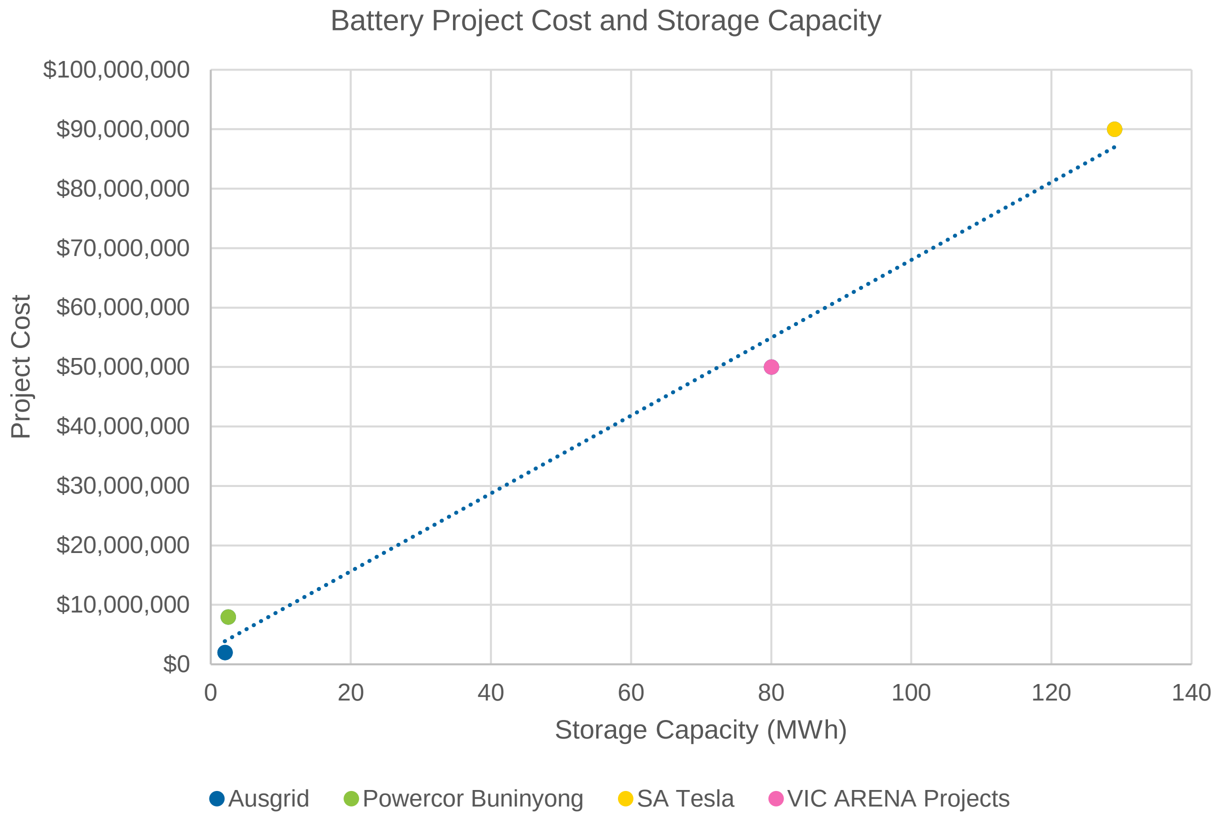
The major assumptions of the CBA are the augex deferral period (one year) and battery relocation frequency (three years). These assumptions will obviously be somewhat at the discretion of Ausgrid, but they do have a significant impact on the CBA. Section 6.4.3.6 looks at the sensitivity of the CBA to changes in these assumptions.

### 6.4.3.4 Costs

Ausgrid have assumed a capital cost of $2,000,000 for a 2.5MWh battery ($1,500,000 purchase cost and $500,000 installation), or $800,000 per MWh of storage capacity. This compares favourably with other battery projects of both similar and much larger scale, as shown in Figure 13, when compared to:

- The South Australian Tesla Battery Farm,
- The Powercor Buninyong Battery, and
- The proposed Kerang and Ballarat batteries funded by ARENA and the Victorian government.

*Figure 12: Project cost and MWh storage capacity*




The annual maintenance cost of $10,000 is relatively immaterial in the context of the overall CBA. Furthermore, there are potentially some savings to this cost in the year of relocation by synchronising the relocation and maintenance activities in those years.

#### 6.4.3.5 Benefits

Capex deferral is one of the primary direct benefits. Endeavour Energy has indicated that the inclusion of a 1MW battery within its network offers an opportunity to defer capex by $1M a year[29] in the new development in West Dapto. Clearly in a new development a fixed location battery has the potential to defer augmentation capex for a longer period than a brownfield site, however Ausgrid's proposed capex benefits for a 2.5MWh battery of $2.3M over ten years may still understate what the actual capex benefits of this approach are likely to be. With a financing rate of 3.92% and an installation cost of $25M for a zone substation, every year a project is deferred is a benefit of approximately $1M. The reason Ausgrid's estimated capex benefit of $2.3M[30] is below what would be expected of an annual deferment is that the business case assumes the deferral of one year's capex and then a relocation of the battery every three years. This could be considered a worst case scenario as relocation not only brings about a reduced benefit but also incurs relocation costs ($600,000 has been used in Ausgrid's proposed business case).

Ausgrid's business case also does not propose any opex benefits from the project, however with the deferral of network augmentation there is likely to be deferred opex for the maintenance of these assets in the

[29] https://reneweconomy.com.au/endeavour-energy-to-deploy-large-scale-storage-to-reduce-network-investment-84433/

[30] $2.3M is the NPV of three $1M deferrals in the future – Ausgrid has nominated the years 2023, 2026 and 2029.

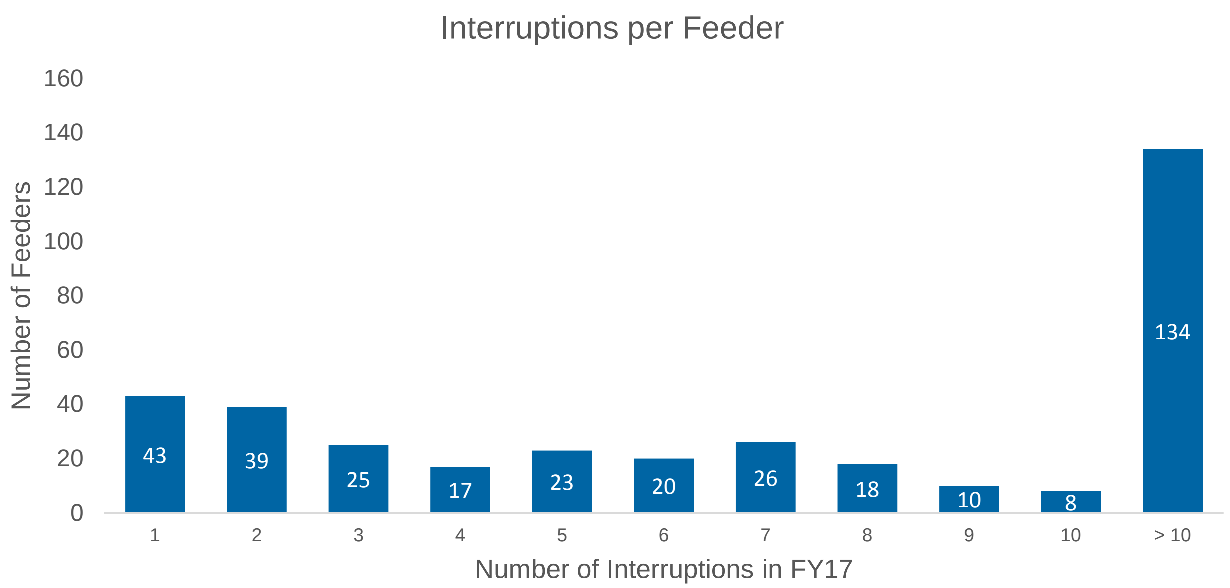
following years. If we estimate the annual avoided maintenance benefit to be approximately $31,000[31] (which represents the average maintenance opex Ausgrid incurred at each of its zone substations in 2016/17), then incorporating this opex benefit into the CBA in the years prior to the relocation of the battery (i.e. the year in which the opex is avoided by the deferral of the capital solution) changes the analysis as follows:

1. The Benefit to Cost Ratio moves from 1.01 to 1.03; and
2. The NPV over the period increases from $37,161 to $83,706.

As discussed earlier, battery technology costs are only recently trending towards a point to make projects like this economically feasible. Other variables that will impact the realised economic value of the solution include the charging cost and discharging price at the times of use.

Ausgrid has assumed $89,999 per annum in avoided unserved energy benefits (at a VCR of $40,000/MWh), based on the assumption of a 0.9 feeder failure rate. It is difficult to validate this assumption without knowing the location of installation and associated feeder characteristics (number of customers, outages and duration per annum), however by comparison the Powercor Buninyong battery solution benefit assumption was 3 outages per annum at an average duration of over 100 minutes in a location servicing 3000 customers. Ausgrid's assumption of 0.9 for the feeder failure rate seems conservative given that this rate is close to the overall average for Ausgrid's network. This average is skewed by the CBD figures. A histogram of number of sustained interruptions recorded per feeder shows that there are many more frequent interruptions on other feeders (Figure 14). At the time that a full business case is prepared for this initiative, we would expect that Ausgrid take this into consideration and the likelihood of a higher failure rate than that assumed for the CBA would be high[32].

***Figure 13: Histogram of 2017 Sustained Interruptions per Feeder***




[31] Ausgrid's zone substation maintenance in 2016/17 across its 222 zone substations was $6,891,356.

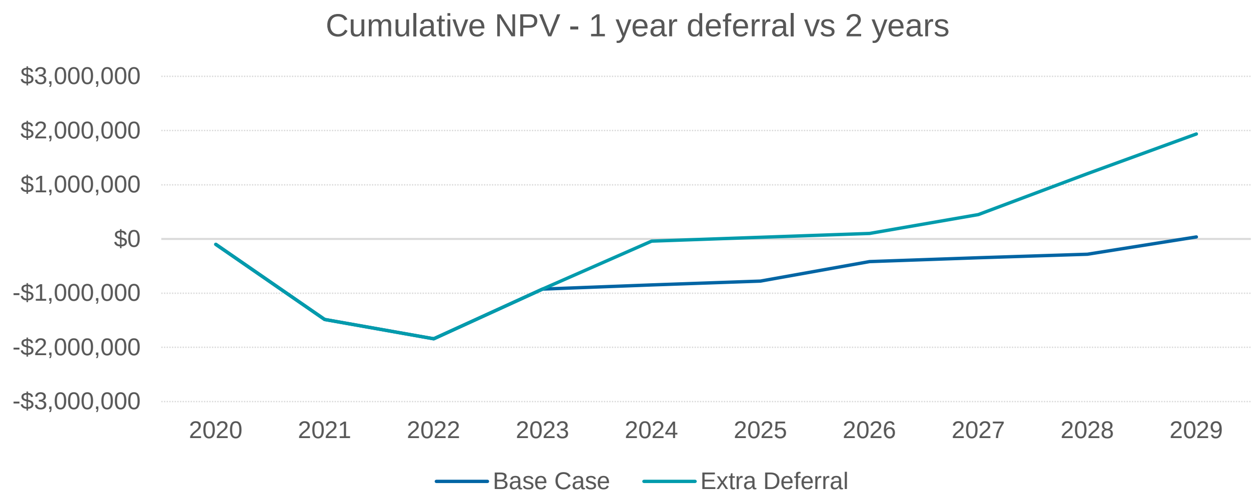
[32] The reliability benefits of a grid battery contribute around 20% of the NPV for this project ($543K of $2.8M)

We would expect that even though the primary purpose of the project is augmentation deferral, that there would be ample opportunities within Ausgrid's service area to locate the battery where not only is the demand close to augmentation triggers but scope for increased reliability are higher than the average.

#### 6.4.3.6 Risk and Uncertainty

As mentioned above, Ausgrid's business case assumes a one year augmentation deferral with a relocation every three years. The three year insitu assumption seems reasonable given the time period to establish a new zone substation, however it is likely that Ausgrid will find opportunities to capture deferral periods longer than a single year. For example, where capex could be deferred for two years, the annualised benefit is doubled and the next relocation cost is also deferred by an extra year. The impact of a two year deferral period and a four year relocation assumption are shown in Figure 15 below.

***Figure 14: Base Case NPV vs Extended Deferral Period***




The different scenario highlights the impact that increases in augmentation deferral time have on the benefits accrued.

## 6.5 Advanced EV Charging Platform Trial

This project aims to develop an Electric Vehicle (EV) system to facilitate and support EV connections to the grid whilst managing impacts on the network. The list of CBA parameters analysed for this project are shown below.

***Table 14 - EV Charging Platform CBA Parameters***

| Demand Forecasts | Unit Rates | Assumptions | Costs | Benefits | Risk and Uncertainty |
|---|---|---|---|---|---|
| Volume of EVs | Substation augmentation cost ($ per MVA)<br><br>HV Feeder augmentation | % of demand growth leading to augex<br><br>Substation capacity factor (%) | System development cost | Total avoided augmentation capex | Sensitivity to demand variance<br><br>Overestimation of augex and |

| Demand Forecasts | Unit Rates | Assumptions | Costs | Benefits | Risk and Uncertainty |
|---|---|---|---|---|---|
| | cost ($ per MVA) | HV feeder capacity factor (%) | | | demand relationship |

### 6.5.1 The problem being solved

Whilst the uptake of EVs in Australia is currently relatively low, research suggests that price, range and infrastructure are the prohibitive factors, rather than consumer will. AEMO's latest forecast for EVs has become more aggressive, driven partly by the advancements in range and reductions in price. Bloomberg New Energy Finance predicts that EVs will be cheaper than combustion engine vehicles by 2025[33] – the first year in the Ausgrid CBA that realises a capex benefit.

Infrastructure Victoria recently released a report on the transition to automated and zero emission vehicle infrastructure[34]. Amongst other findings, the report states that electricity consumption by EVs in Victoria could be between 21,700 and 24,100 GWh by 2046, which could require additional investment in energy generation, transmission and distribution infrastructure of between $5.2 and $9.7 billion. Recommendation 11.b of the report states:

> *"Ensure that the regulatory frameworks governing network investment are reviewed to check that these will facilitate investment in the distribution network to support the uptake of zero emissions vehicles. This includes advocating that the Australian Government work through the COAG Energy Council to review regulatory settings and remove barriers to distributors addressing highly-localised impacts of zero emissions vehicles uptake."*
>
> Infrastructure Victoria, Advice On Automated and Zero Emissions Vehicles Infrastructure, October 2018

Whilst the increase in demand that is forecast to accompany uptake of EVs is significant, there is some capacity to absorb the rise in peak demand at the system level through existing substation utilisation "headroom". The greater challenge may be countering the effects below the substation level – localised impacts of EV charging that may impact the reliability of the network. How network businesses respond to EV uptake will determine the magnitude of the impact on the grid. Network service providers have several options, including encouraging shared charging depots in optimal locations (low utilisation, short distance from high voltage lines), incentivising charging in off-peak hours and harnessing EVs as DERs by buying back power from consumers. Any response, however, will require a broader and more granular level of information on EV penetration, charging patterns and consumer behaviour than is currently available. We therefore consider that this project is a precursor to the ability to respond to the upcoming surge in EV uptake that, if executed effectively, will position Ausgrid to make prudent future network decisions around EV integration.

[33] BloombergNEF, Electric Cars to Reach Price Parity by 2025, June 2017

[34] Infrastructure Victoria, Advice On Automated and Zero Emissions Vehicles Infrastructure, October 2018

### 6.5.2 Innovation

EV uptake and the associated penetration of charging infrastructure are forcing changes to the way in which distributors plan and manage the network. Whilst the challenge is common to all distributors, the issue is emerging simultaneously for all industry participants and therefore require innovative responses.

### 6.5.3 Reasonableness of the costs and benefits

The Advanced EV Charging Platform has a 10 year NPV of $339,090 and a Benefit to Cost Ratio of 1.33.

#### 6.5.3.1 Demand forecasts

The demand forecast for future volumes of EVs is based on the latest AEMO report, which we consider a credible reference point. Ausgrid has used the neutral uptake scenario, but also calculated the high uptake scenario (NPV of $2,591,374). In section 6.5.3.6 we test the sensitivity of the CBA outputs to the potential eventuation of the low uptake scenario.

#### 6.5.3.2 Unit rates

The CBA relies on unit rates of substation and HV feeder augmentation from the augex model. We note that the unit rates selected by Ausgrid for the CBA analysis are based on the costs in the urban category. Short and long rural augex rates are higher for both asset types. We consider, therefore, that this unit rate assumption is conservative.

#### 6.5.3.3 Assumptions

Like the unit rates, Ausgrid has selected the urban category of the assets for the capacity factors assumed. The other assumption is the correlation between demand and augmentation, with 2.5% of total demand assumed to lead to an augex solution. Linking peak demand to localised augmentation triggers is difficult to evaluate, but on face value the assumption does not seem unreasonable. In section 6.5.3.6 we test the CBA output sensitivity to change in this assumption.

#### 6.5.3.4 Costs

It is difficult to evaluate the proposed costs of a system solution that has yet to be fully specified. One comparison point we do have is that of a proposed AusNet Services innovation project to “conduct a detailed EV network impact study, modelling, and EV clustering demonstration trial that tests response to tariffs and charging management solutions”[35]. This project is estimated at $1.0 million compared to Ausgrid’s $1.2 million. We consider this a reasonable comparison given that the Ausgrid project is on a larger scale network, the AusNet trial is a continuation of work previously funded and the Ausgrid project should result in an operational platform, rather than just a trial.

#### 6.5.3.5 Benefits

The stated benefits are purely the avoided augmentation capex potentially available through greater insight into EV charging locations and behaviours. Benefits clearly extend beyond avoided augmentation into insights that can inform tariffs that encourage charging behaviours, carbon offsets, incentives to access EV batteries as DERs and avoidance of instabilities and outages caused by mass charging at peak times on hot days. These benefits are difficult to quantify with the information that would be available through the successful execution of this project, so we are satisfied that the benefit scope is at this stage confined to the augmentation avoidance or deferral. We do consider, however, that there is a potential for overstatement of these types of benefit as various studies consider the extant network capacity has sufficient headroom for

[35] AusNet Services, Innovation Expenditure - Negotiating position for the Customer Forum, 2021-25.

EV penetration. This of course is a macro view of what will be a micro consideration, but the critical assumption here is not only the penetration rate, but the assumption that 2.5% of all new demand leads to an augex solution. This is tested in the next section.

#### 6.5.3.6 Risk and Uncertainty

The key uncertainties in the CBA are the selection of the neutral uptake scenario for EVs from the AEMO report and the assumption that 2.5% of demand growth leads to an augex solution. Figure 16 shows the difference in outcome if the low EVA uptake scenario is used for the cost benefit analysis and Figure 17 shows the sensitivity to the demand growth assumption.

The low EV uptake scenario is NPV negative and does not breakeven in the ten year period. As such, Ausgrid should monitor actual EV uptake so that project termination can be executed if prudent to do so. The BCR crosses parity at an assumption of 1.9% of peak demand leading to augex. Whilst this margin of error is relatively slim, we consider this risk is offset by the externalities that are not currently considered by the CBA.

***Figure 15: EV Uptake Scenario Sensitivity***

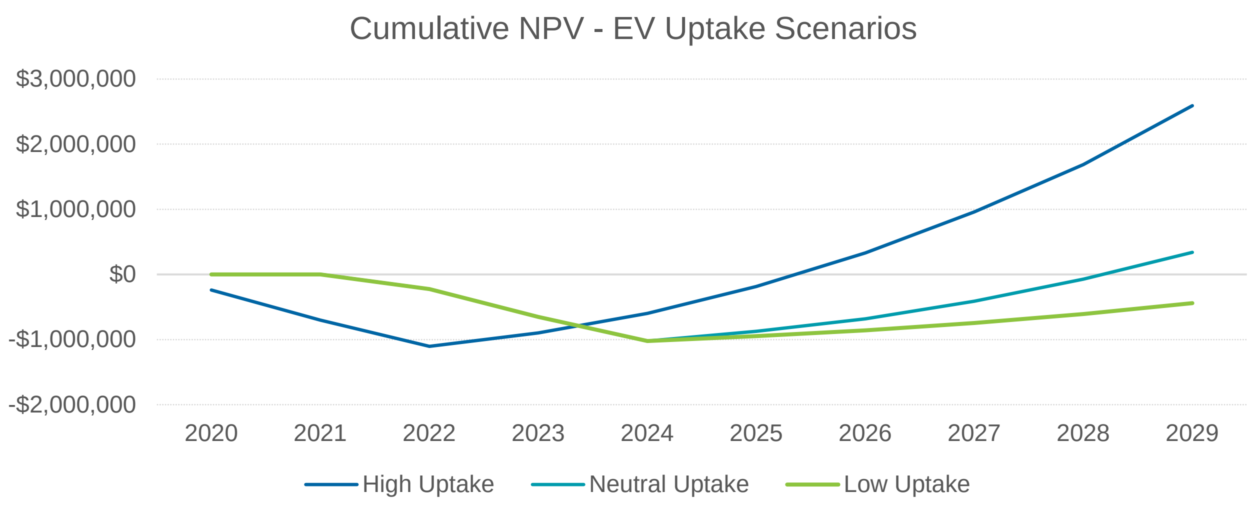
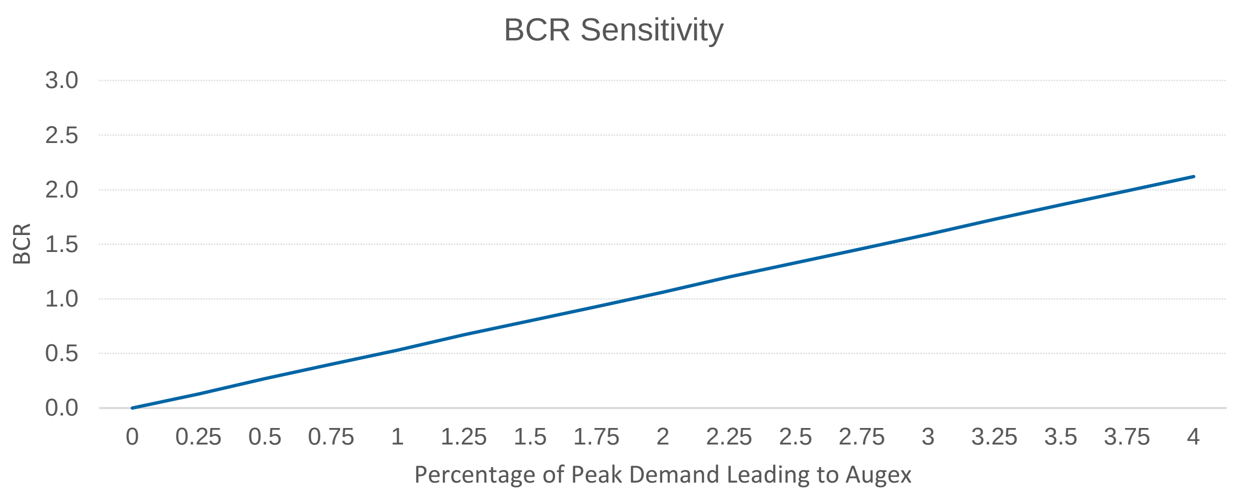



***Figure 16: Sensitivity of CBA to Demand Growth Assumption***



## 6.6 Portable All-in-One, Off-Grid Supply Units

*Table 15 –Portable All-in-One, Off-Grid Supply Units CBA Parameters*

| Demand Forecasts | Unit Rates | Assumptions | Costs | Benefits | Risk and Uncertainty |
|---|---|---|---|---|---|
| Annual use | No applicable unit rates have been used | Value of unserved energy<br>Customer demand | Capex cost to acquire<br>Ongoing maintenance opex | Reduction in unserved energy | Annual use |

### 6.6.1 The problem being solved

This initiative will trial the use of portable, modular off-grid energy supply units that can be deployed rapidly and provide grid quality supply to a customer (or customers) for an extended period without a physical grid connection. There are multiple uses for portable off grid power, and this trial would be expected to test all such cases, including providing additional support during network maintenance, supporting remote and vulnerable customers during extended planned and unplanned outages, or islanding customers to alleviate bush fire risk, or assessing the suitability of permanent ‘off-gridding’. This initiative will evaluate the effectiveness of several off the shelf units to deliver improved customer outcomes.[36]

### 6.6.2 Innovation

The innovativeness of this projects is due largely to the proposed uses rather than the underlying technology. For example, islanding customers on high bushfire risk days to alleviate bushfire risk would be an innovative implementation of standalone power systems. Energy Safe Victoria in a recently published report have used machine learning to identify weather conditions that increase the probability of a fire incident on Victorian networks.

> *“We analysed the effects of 17 separate meteorological factors using machine learning and cluster analysis, and found the most influential factors that trigger and increase the number of incidents during the last three fire seasons. In order of importance, these were temperature, maximum wind gust speed and the temperature differential over the preceding three days. Based on these factors, days in the fire seasons can be partitioned into six clusters with different levels of fire risk.”*
>
> Energy Safe Victoria, 2018, End of Season Fire Report 2017-2018, page 15, Melbourne Victoria

ESV’s analysis indicated that when certain environmental criteria were met (temperature greater than 31 degrees, gust speed above 85km/h) the probability of a fire incident were greater than 91%. Whilst this analysis was conducted on Victorian networks, the conditions that cause fire incidents on Victorian networks are a good indication of what is likely to occur in Ausgrid’s network – particularly in areas of high vegetation density. If Ausgrid were to use standalone power systems at times of high or catastrophic fire danger this would be an innovative use of existing technology.

[36] Page 14 of 22, Ausgrid’s Regulatory proposal – Attachment 5.13.L – Operational technology & innovation

### 6.6.3 Reasonableness of the costs and benefits

#### 6.6.3.1 Demand forecasts

The key assumption used by Ausgrid is that these systems will be operational for 2,496 hours per annum. This equates to each power system being relied upon for 12 hours each week for a combined utilisation of 48 hours per week. Given that in 2016/17 Ausgrid had an average outage time of 538 hours per week we believe that it is a reasonable assumption that Ausgrid will be able to utilise these standalone power units for at least 48 hours per week.

#### 6.6.3.2 Unit rates

No unit rates have been used in the CBA.

#### 6.6.3.3 Assumptions

The primary assumption is the estimated demand from each customer with a value of 1.5 kW per hour being used. Using Ausgrid's reported total energy delivered value of 25,669 GWh in 2016/17 and the number of customer connections[37] gives a per hour estimate of 1.72 kWh. This suggests that the value of 1.5kW used as an assumption is reasonable.

#### 6.6.3.4 Costs

[redacted]

#### 6.6.3.5 Benefits

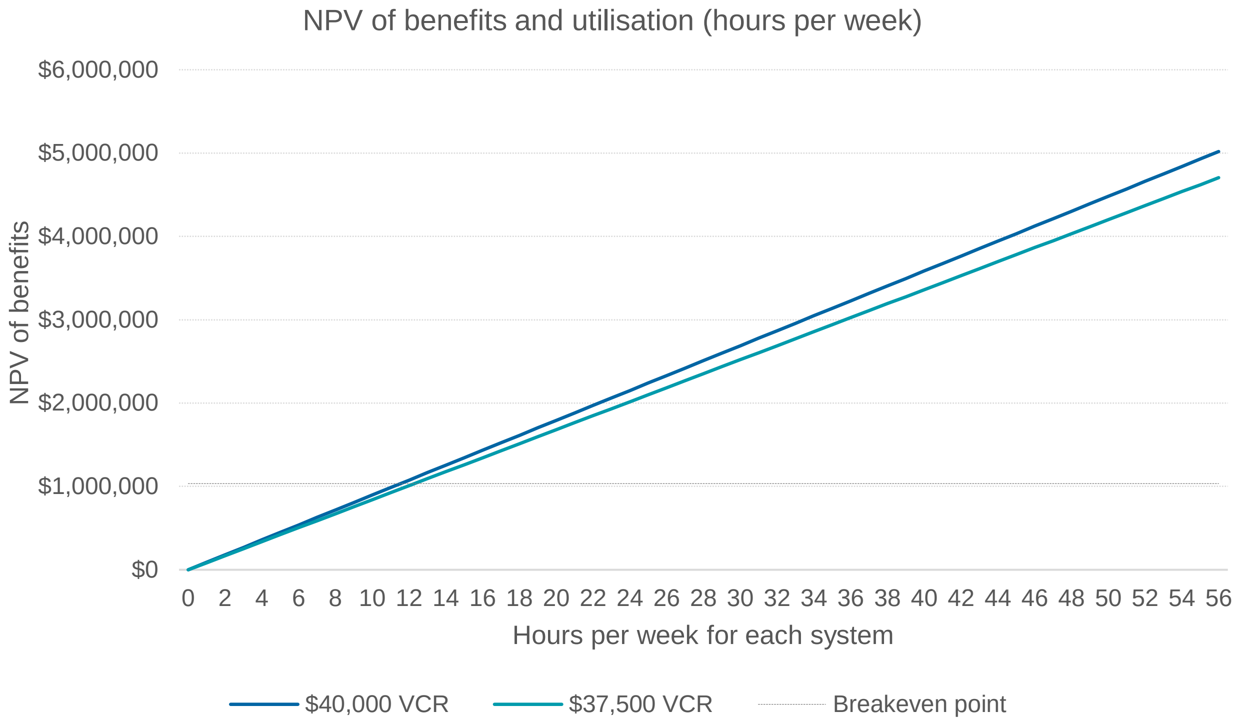
The quantified benefits of the portable supply units business case are for the improved reliability associated with having a separate power system. The value of unserved energy used is $40,000 per MWh. As mentioned above, the AER in its Annual Benchmarking Report uses a figure of $39,500 for Ausgrid's value of unserved energy. In the analysis below we use both values as part of the sensitivity testing for this project.

#### 6.6.3.6 Risk and Uncertainty

The uncertainty in defining the benefits of this program are largely due to the different ways in which the off grid power systems could be used. For example, if the systems were used exclusively to provide power in times of planned maintenance the benefits would significantly exceed the costs. The graph below indicates the NPV breakeven point for this project with respect to the number of hours the four systems are utilised per week. Two values have been used to measure the Value of Customer Reliability, these are the $40,000 used by Ausgrid and $39,500 used by the AER for benchmarking purposes. We have used an average customer demand of 1.5kW and assumed that each system provides power to a single customer when operational.

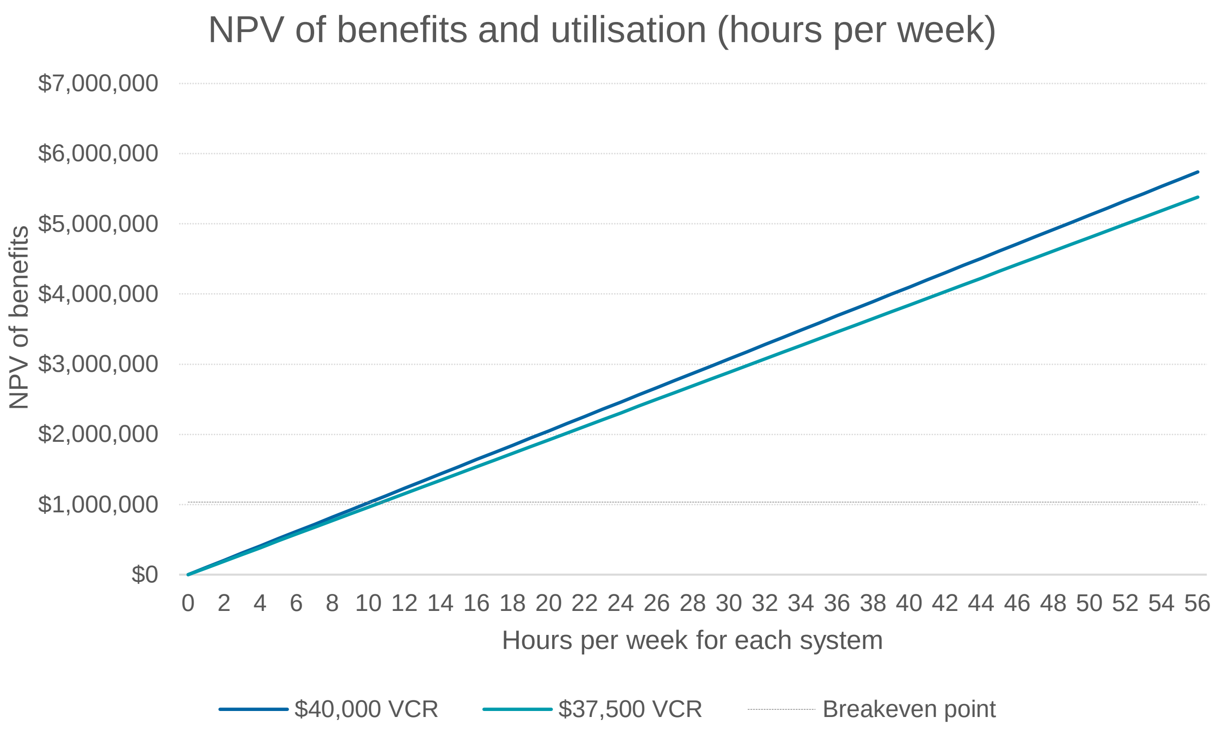
[37] 1,706,913 customer connections

*Figure 17: Benefit NPV and Utilisation Assumption*




The graph above indicates that with Ausgrid's assumption of 12 hours per week utilisation per power system the project is NPV positive with a $40,000 per MW and close to neutral with a VCR of $37,500. Using a demand profile of 1.72 kWh per customer, the value derived from Ausgrid's benchmarking RIN results in the project being NPV positive with both reliability values. This is displayed below.

*Figure 18: Benefit NPV and Utilisation Assumption - 1.72kWh per customer*




The analysis above is likely to undervalue the actual benefits that could be obtained by the use of standalone power systems to mitigate power interruptions. This is because the analysis uses average values[38] which ignores Ausgrid's ability to select which situations the power systems will be relied on. Ausgrid's ability to select where and when these assets are utilised means that they could be rolled out for customers with higher than average demand or in situations where the value of reliability exceeds $40,000 per MWh.

In addition, Ausgrid has proposed the use of these systems to investigate the opportunity to island customers in high bushfire risk areas and the suitability of employing permanent off-gridding which will bring their own benefits such as a reduced fire risk and lower average network costs.

Like many of the projects in Ausgrid's innovation program, there is little doubt that implementing these solutions on Ausgrid's network can result in benefits that exceed the costs of implementing them. The challenge will be having a governance process in place that ensures the benefits and costs associated with each program are clearly defined and recorded. In the case of off-grid supply units this means having a clear objective for what these systems are to be used for, a set of criteria that enables prioritisation of unit utilisation[39] and a system that enables the benefits of these units to be recorded and incorporated into future decisions.

## 6.7 Self-Healing Networks

The list of CBA parameters analysed for this project are shown below.

[38] Customer demand and the value of customer reliability are both averages for Ausgrid's entire network

[39] For example, where there are multiple planned outages what are the criteria that decides which customer has access to ongoing power supply?

*Table 16 – Self-Healing Networks CBA Parameters*

| Demand Forecasts | Unit Rates | Assumptions | Costs | Benefits | Risk and Uncertainty |
|---|---|---|---|---|---|
| None used | None used | VCR of $40,000 | Opex and capex costs per project | Value of reliability | Size of reliability benefits |

### 6.7.1 The problem being solved

This project aims to trial self-healing network technology to identify faults, isolate portions of the network and restore supply without intervention from an operator. This is a key enabling step to develop an understanding of automated networks which will in future periods (following full commissioning of an ADMS and associated advanced functionality) enable more efficient operations, reduced unserved energy and allow more efficient augmentation expenditure.

A significant proportion of a networks total outage time can be attributed to the time taken to access and identify faults on the network. Fault detection, isolation and restoration technology (FDIR) has the potential automate what has historically been a manual restoration process.

### 6.7.2 Innovation

To some extent, all electricity distribution networks within the NEM are trialling or experimenting with automated fault detection and restoration[40]. This project will build on previous implementations of FDIR technology in the Newcastle Region of Ausgrid's network to ensure the technology and its interactions with other assets on the network are well understood by Ausgrid's control room. In this context, the self-healing network project will continue work already undertaken by Ausgrid to ensure there is a sufficient body of knowledge within the organisation to implement the technology when the ADMS is fully commissioned.

### 6.7.3 Reasonableness of the costs and benefits

#### 6.7.3.1 Demand forecasts

There are no demand forecasts relied upon within this business case.

#### 6.7.3.2 Unit rates

There are no unit rates used in this business case.

#### 6.7.3.3 Assumptions

Ausgrid have assumed a value of customer reliability of $40,000 for this project. This is greater than the value of $39,500 used by the AER in its Annual benchmarking Report. In the current business case the project NPV, given the estimated improvements in reliability, is $101,000. Using a value of $39,500 brings the project closer to neutral with an NPV value of $25,000.

#### 6.7.3.4 Costs

It is difficult to access publicly available data to verify the costs of the hardware, software and installation required for the implementation of FDIR systems. The hardware and software costs which are procured from

[40] See https://www.smh.com.au/business/the-economy/the-self-healing-system-designed-to-keep-western-sydney-s-lights-on-20181016-p50a0c.html for an example from Endeavour Energy

the competitive market make up more than half the cost of the capex required for the project. In addition, the benefits and costs are based on a detailed 2018 business case that has taken into consideration the costs and benefits of the implementation of FDIR technology in the Newcastle region of Ausgrid's network. Given these costs are based on previous implementations of this technology we believe these proposed costs are likely to be reasonable.

#### 6.7.3.5 Benefits

Ausgrid have indicated annual benefits of $23,039 for each part of the network FDIR technology is installed on. These benefits are derived from reductions in unserved energy as faults on the network are restored quicker. To test the reasonableness of this assumption we have used information provided in Ausgrid's 2016/17 Economic Benchmarking RIN. This analysis is presented in the table below.

***Table 17: Ausgrid RIN Variables, 2017***

| Measure | Value |
|---|---|
| Energy not supplied (MWh) | 20,097 |
| Total sustained interruptions | 1,244 |
| Average MWh not supplied per interruption | 1.62 |
| Value of each outage (VCR $40,000 per MWh) | $64,601 |
| Value of each outage (VCR $39,500 per MWh) | $63,990 |

Using the value of each outage above, we can calculate the assumed improvements in reliability that result in the $23,039 benefit assumed be Ausgrid in the business case. Using a value of unserved energy of $40,000 per MWh would require a 35% reduction in outage time whilst a value of unserved energy of $39,500 per MWh would require a reduction of 36% outage time to produce a benefit of $23,039. Like the portable power supply program, there is the potential for self-healing networks to reduce outage time and emergency response expenditure that negate the capital and ongoing operating expenditure required. Realisation of these benefits will require detailed examination of which parts of Ausgrid's network are best suited for this technology. Areas of the network with regular outages and/or in areas with a high value of customer reliability should be identified to ensure locations are selected that provide the greatest benefit relative to cost. In addition, benefits associated with improved reliability and reduced emergency maintenance expenditure should be documented so these improvements can be incorporated into ongoing productivity improvements.

#### 6.7.3.6 Risk and Uncertainty

The primary risk of this project is that reliability benefits do not cover the capex and installation costs of the technology. We note that Ausgrid have proposed to incorporate this technology over five sites between 2020 and 2024. This means that this risk can be mitigated through monitoring from the Network Innovation Advisory Committee to ensure that the costs and benefits proposed are being met.

## 6.8 Dynamic Load Control

The list of CBA parameters analysed for this project are shown below.

***Table 18 – Dynamic Load Control CBA Parameters***

| Demand Forecasts | Unit Rates | Assumptions | Costs | Benefits | Risk and Uncertainty |
|---|---|---|---|---|---|
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

### 6.8.1 The problem being solved

Historically, network constraints have been largely solved through augmentation of the network. The introduction of smart meters and the availability of real-time electricity consumption data provides an opportunity for networks to offer different tariff structures in exchange for control of customer loads at different times of the day. Being able to adjust customer loads at times of network constraints means that networks can defer augmentation in constrained locations. In addition, the successful use of demand management may over time offer the ability to not only defer augmentation expenditure but also avoid replacement expenditure.

### 6.8.2 Innovation

The use of dynamic load controls is not an innovative solution in itself, currently Ausgrid operates a load control program controlling the loads of nearly 500,000 hot water storage heaters on its network. If this project is to be innovative it will come from the opportunity to offer greater pricing flexibility to customers in areas of high network constraints and in understanding the different electricity consumption characteristics of its customers.

### 6.8.3 Reasonableness of the costs and benefits

#### 6.8.3.1 Demand forecasts

Ausgrid has assumed an annual increase in remote control enabled smart meters of 40,000 per annum. This means that the population of smart meters that are remote controlled increases from 40,000 in 2020 to 400,000 in 2029. In the context of Ausgrid's overall forecast decline in type 5 meter population of 123,504 meters per year[41] between FY18 and FY24[42] this assumes that approximately a third of installed smart meters will be remote control enabled.

#### 6.8.3.2 Unit rates

[redacted]

[redacted]

[redacted]

### 6.8.3.3 Assumptions

### 6.8.3.4 Costs

[redacted]

### 6.8.3.5 Benefits

[redacted]

- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

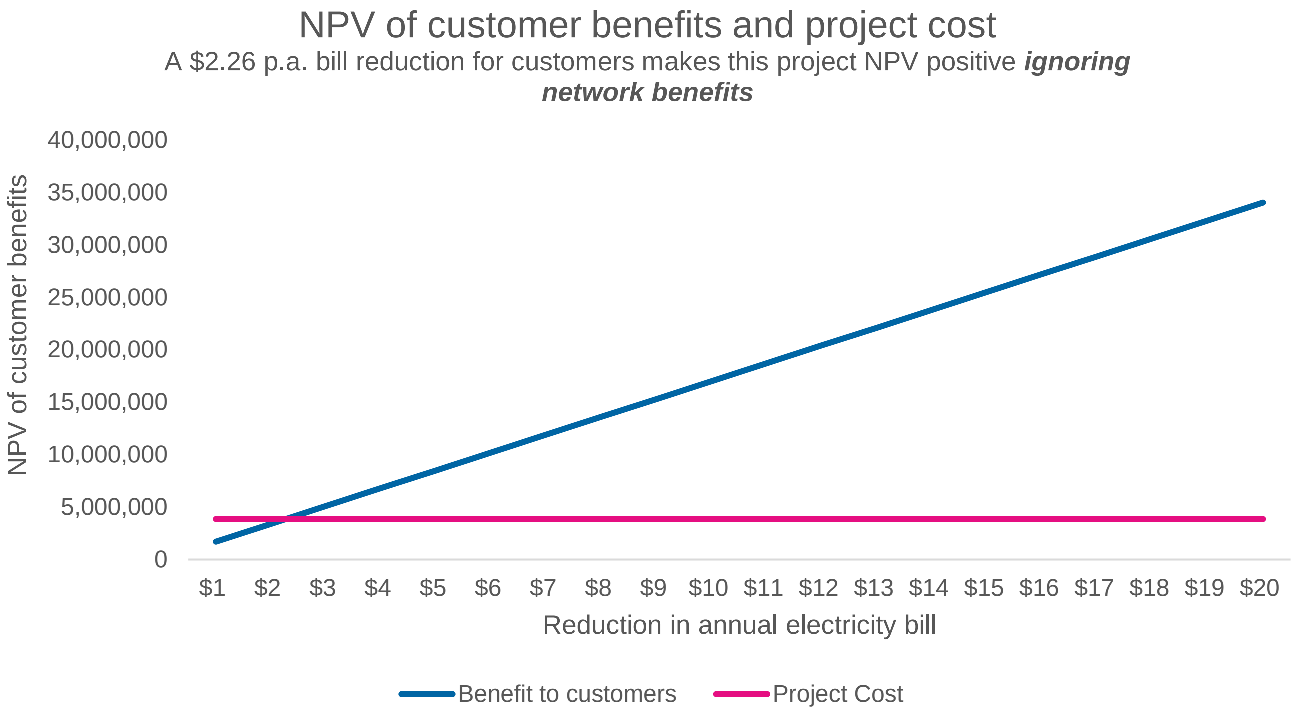
[redacted]

| | [redacted] | [redacted] | [redacted] |
|---|---|---|---|
| [redacted] | [redacted] | [redacted] | [redacted] |

The table shows that a $1 per annum reduction in the bills of customers within this program will accrue $1.7M of benefits for Ausgrid customers. This relationship between price reductions and NPV is linear (each $1 reduction in the bills of Ausgrid customers involved increases the project NPV by $1.7M). This indicates that modest reductions in customer bills would produce a positive project *NPV regardless of the network benefits identified by Ausgrid*. This is illustrated below.

[43] Customer benefits have been calculated from 2022 to maintain consistency with the benefit period used in Ausgrid's business case. This indicates that benefits from this project will accrue from 2022.

*Figure 19: NPV of Customer Bill Benefits*




The chart above shows that if each of the customers with dynamic load control enabled save on average $2.26 this project will be NPV positive regardless of any network benefits identified by Ausgrid. Canstarblue analysis suggests that average customers on controlled loads can save between $208 and $248 per annum on controlled loads[44], much of these savings are due to controlled water heating loads already implemented on Ausgrid's network, however the ability to control other loads such as air conditioning and pool pumps through the implementation of this technology means that a reduction in the average customer bill of $2.26 should be attainable.

#### 6.8.3.6 Risk and Uncertainty

The uncertainty in this project is the forecast number of meters with access to remote controlled monitoring and the benefits that have been identified. To a large extent the risk of errors in the forecast number of meters with remote controlled technology is mitigated as 85% of the project costs vary directly with meter volumes. The uncertainty associated with the proposed benefits can be mitigated through the oversight of the Network Innovation Advisory Committee. This is because the project is scheduled to be rolled out between 2020 and 2029 providing the NIAC with the opportunity to review the project regularly to ensure Ausgrid customers are benefitting, either directly through reduced electricity bills or indirectly through reductions in network costs.

## 6.9 Asset Condition Monitoring

The list of CBA parameters analysed for this project are shown below.

[44] https://www.canstarblue.com.au/electricity/controlled-load-tariff-can-save-money/

*Table 20 – Asset Condition Monitoring CBA Parameters*

| Demand Forecasts | Unit Rates | Assumptions | Costs | Benefits | Risk and Uncertainty |
|---|---|---|---|---|---|
| None used | Historic underground feeder augex | 1 year deferral | Capex costs,<br>Opex costs | Deferred augex | Length of avoided augex |

### 6.9.1 The problem being solved

Increasing intermittent generations from renewable energy, a reduced appetite for network augmentation and reductions in the costs of asset condition monitoring technologies means that networks are now expected to operate at higher asset utilisations whilst simultaneously balancing two way electricity flows. In order for these expectations to be realised, networks require real time information on the performance of their assets. Technology enabling dynamic asset ratings have been funded in the U.K through the Low Carbon Networks Fund with a summary of the benefits provided in the quote below.

*"The present industry best-practice for network planning and design uses the static thermal rating of assets (i.e. overhead lines, cables and transformers), based on representative equipment loadings and typical seasonal ambient conditions, to determine capacity. In real-time network operation, allowing more electricity to flow through an asset than it is designed to carry can cause excessive heat and can potentially result in asset damage and network outages. Consequently, the use of generic asset ratings that do not consider the actual thermal conditions experienced can lead to unnecessary triggering of network reinforcements and corrective measures to reduce load due to indications that thermal headroom is breached."*

EA Technology Report – Summary of the Low Carbon Networks Fund learning, page 19

### 6.9.2 Innovation

Whilst the use of dynamic ratings in the U.K is increasingly considered 'Business as usual' in the U.K[45] it can still be considered innovative in the Australian context. Ausgrid's justification for this project is that it will assess and productionalise real time asset conditioning monitoring on its network and integrate with the ADMS.

### 6.9.3 Reasonableness of the costs and benefits

#### 6.9.3.1 Demand forecasts

None relied on.

#### 6.9.3.2 Unit rates

The unit rates relied upon by Ausgrid are taken from the 2017 Category RIN and are the average of three augmentation projects in which underground cables where installed. These are included in the table below.

[45] Page 14, Summary of Low Carbon Networks Fund learnings

*Table 21: Ausgrid Project Costs*

| Name | Circuit km added | Project cost |
|---|---|---|
| Engadine Zn NEW 132kV Feeders | 6 | $13,460,762 |
| 132KV Feeders 9E3 & 9E4/2 Lindfield - Willoughby STS Replacement | 9 | $33,786,447 |
| Empire Bay Zn 66KV Feeders 883 & 884 | 8 | $32,048,584 |
| **Average** | **8** | **$26,431,000** |

There will be significant variations in project costs depending on the voltage, location and accessibility characteristics of an underground augmentation project. Ausgrid's use of historic augmentation expenditure is an appropriate estimate of the costs of an average cable augmentation project, however when deciding which assets the proposed technology will operate on, it would be expected that it would be installed in an area at the higher range of augmentation costs. For example, if faced with the choice of the three projects above and all else being equal, Ausgrid should install the technology on the Lindfield-Willoughby STS Replacement to ensure the greatest benefits from deferral are achieved.

#### 6.9.3.3 Assumptions

Ausgrid has assumed a one year expenditure deferral from the implementation of this project. Similarly to the assumptions listed in the Grid Battery Trial projects we believe this understates the potential benefits of the technology. With uncertain demand forecasts and declining peak demand on many areas of Ausgrid's network, it is likely that there are locations in which dynamic ratings and an understanding of the actual ratings of Ausgrid's cables can delay augmentation for longer than a single year.

#### 6.9.3.4 Costs

Ausgrid has proposed a capex cost of $600,000 and annual maintenance costs of $50,000 for this project. Without a detailed understanding of the specific technology and location this technology will be installed in it is difficult to assess the efficiency of these costs. Annual maintenance of $50,000, or 8.3% of the asset value, can be considered high particularly given Ausgrid's underground maintenance costs in 2016/17 were $1.8M, or 0.04% of their underground RAB[46].

#### 6.9.3.5 Benefits

Ausgrid has identified benefits associated with a single year of deferred cable augmentation. As detailed in the Assumptions section above, we believe this to understate the actual benefits that could be accrued through the strategic placement of this technology on Ausgrid's network. If Ausgrid target an underground cable that is costly to augment, in an area with uncertain future load growth and environmental

[46] Underground RAB of 5,060,956,088has been taken from 2016/17 Economic benchmarking RIN

characteristics that mean dynamic ratings are likely to be lower than the current static thermal ratings it is likely that greater deferral periods can be achieved.

#### 6.9.3.6 Risk and Uncertainty

The risks associated with this project rest entirely on the ability of the proposed technology to defer underground cable augmentation. Failure to defer augmentation for a year will results in a negative NPV (-$936k), a year deferral will result in a negative NPV (-$113k) whilst any deferral period greater than 18 months will result in a positive NPV. Like many of the projects in Ausgrid's Network Innovation Portfolio, the benefits of the technology are likely to have significant benefits to customers (in this case deferred augmentation) if the technology is used in a part of Ausgrid's network that maximises benefits.

## 6.10 Line Fault Indicators

Advanced line fault indicators, with remote communications capability, can reduce operational expenditure during incident management and improve customer reliability outcomes. This project funds the investigation of newer SCADA enabled line fault indicators in a variety of locations to assess suitability for a broader roll-out, as well as the system integration required to incorporate into an ADMS. The list of CBA parameters analysed for this project are shown below.

***Table 22 – Line Fault Indicators CBA Parameters***

| Demand Forecasts | Unit Rates | Assumptions | Costs | Benefits | Risk and Uncertainty |
|---|---|---|---|---|---|
| Not applicable | Patrol costs | Number of annual faults impacted<br>Typical time saving<br>Average customers who benefit | Cost of LFI installation<br>Annual maintenance | Patrol time opex saving<br>Avoided unserved energy | Variation in faults impacted<br>Variation in time saved |

### 6.10.1 The problem being solved

When a fault occurs on the network, significant time is spent by rectification crews in locating and isolating the source. This troubleshooting activity can expose technicians to safety risks and equipment to damage. Line fault indicators are a proven technology that, when placed and operated correctly, can reduce restoration times and increase safety through indication of the location of a fault current event on conductor and cable.

### 6.10.2 Innovation

The use of line fault indicators is not a novel approach, however the optimal placement of the indicators requires a scientific approach to identification of the most effective number and location of the equipment. This is not a one-size-fits-all solution and Ausgrid will need to determine where and how many fault line indicators will achieve the best outcome for it based on its network characteristics.

### 6.10.3 Reasonableness of the costs and benefits

The ten year NPV of this project is forecast to be $64,855 with a BCR of 1.11. This type of project has a moderate direct opex productivity saving due to reduced patrol/fault finding time (assumed to be 20 minutes per location and fault), which translates to a net present value of productivity benefits of $9,225 over the ten years. This is compared to a $73,170 NPV of maintenance costs for the devices. The real value in this project is the value of customer reliability that each instance of those 20 minutes of reduced fault finding time represent. The avoided unserved energy benefit NPV over the ten years is forecast at $664,221. This value will depend upon suitable location identification for the indicators.

### 6.10.4 Demand forecasts

There are no demand forecasts applicable to this project.

#### 6.10.4.1 Unit rates

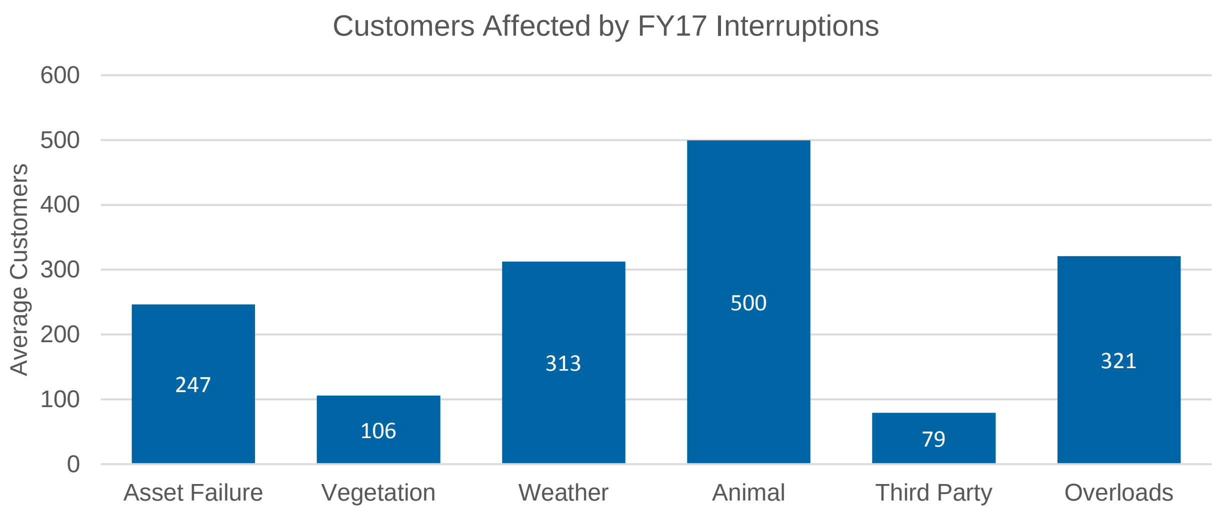
The patrol cost unit rate is assumed to be $100 per hour. Given the average hourly labour rate of a skilled electrical worker according to Ausgrid's category RIN was $62.98 in 2017, we consider this assumption reasonably conservative given:

- On-costs and overheads need to be added to that labour rate to arrive at the true value;
- Vehicle and equipment costs need to be considered; and
- A fault investigation and rectification crew will usually comprise more than one staff member.

#### 6.10.4.2 Assumptions

Ausgrid has assumed an average number of customers affected by faults that would be subject to reduced troubleshooting time of 250 per fault/feeder. In 2016/17 the average number of customers affected by sustained interruptions due to asset failure was 247 according to the 2016/17 Ausgrid category RIN and 321 for overloads. This assumption therefore seems reasonable, perhaps even conservative given we would expect the indicators would be placed optimally to maximise time savings on known worst performing feeders. The average number of customers affected by sustained interruptions by cause is shown in Figure 21.

***Figure 20: 2016/17 Sustained Interruptions by Cause - Average Customers Affected***



It makes sense that vegetation management and third party damage affect a lower number of customers due to the more localised impact of such events. These events would also have more visible indicators for a patrol crew to quickly locate the fault.

The typical time saving of 20 minutes per fault is somewhat speculative, but a U.S. Department of Energy study of 266 Fault Location, Isolation, and Service Restoration operations found that over the year 270,000 customers experienced 38,000,000 fewer minutes of interruption compared to estimated outcomes without fault indication equipment. That equates to 140 minutes per customer, compared to Ausgrid's assumption of 22 minutes (1.1 faults times 20 minutes of saving). That study included networks with remote and automatic switching capabilities, which Ausgrid has the potential to exploit through other innovation projects in its portfolio. However in evaluating the benefits of this project in isolation of the others, the benefits cannot be double counted, so we are satisfied the conservative estimate of 20 minutes is justified.

As with our conclusion that the feeder fault rate assumption for the Grid Battery Trial is conservative given the number of locations with failure rates higher than the entire network average (Figure 14), similarly we feel that this project could be targeted at feeders with higher failure rates than 1.1 per annum to maximise the benefit.

#### 6.10.4.3 Costs

The range of costs for line fault indicator equipment is considerably broad, with many models on the market with varying degrees of functionality. The can range from hundreds of dollars to many thousands depending on the specification. So whilst cost evaluation is difficult prior to vendor and solution selection, the primary driver of value is the optimum location selection of the devices to maximise the benefit. This is not a trivial exercise and we would expect that as the business case for this initiative progresses, appropriate decisions around the capability of devices and optimal location and configuration are made.

#### 6.10.4.4 Benefits

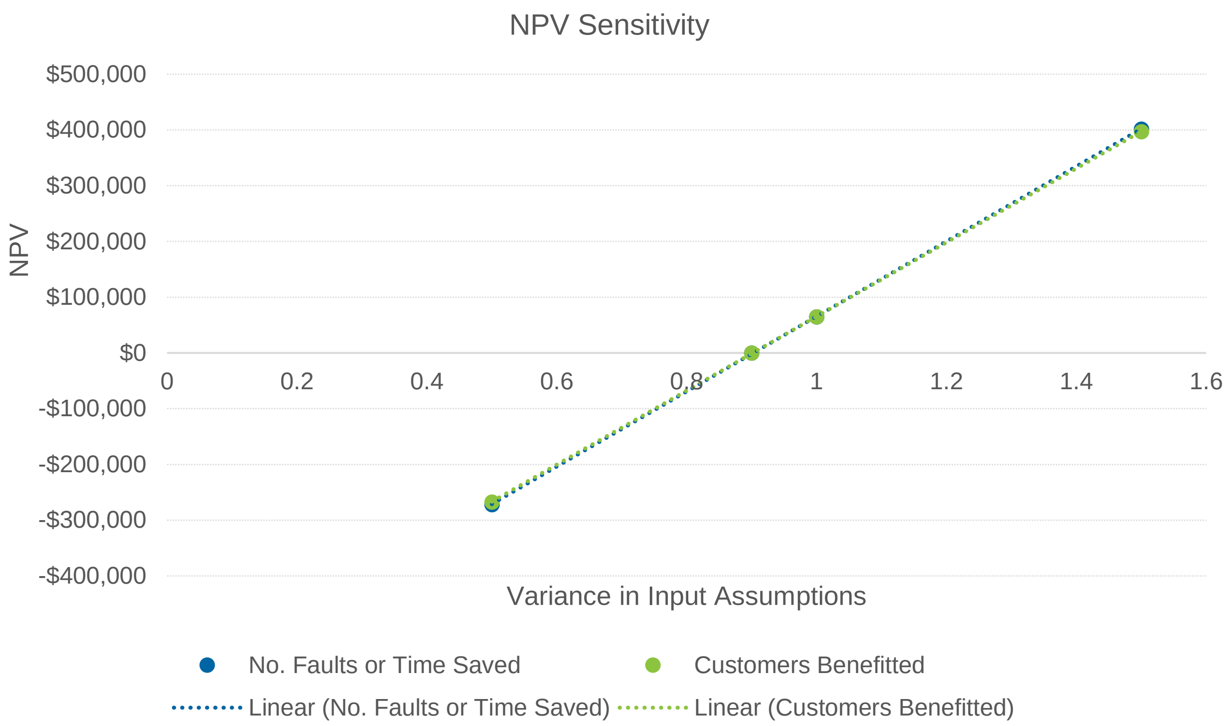
By way of the conservative nature of assumption of time saving and fault rate, we believe the benefit estimation is also somewhat conservative over the period, however we consider this reasonable given the uncertainty of outcomes at this stage. Given the benefits are largely driven by avoided unserved energy, any uplift in minutes saved in patrol/fault isolation time obviously have a significant upside of benefits.

One benefit we do consider missing from the CBA for this project is the safety benefit. Manual fault finding often requires the opening and closing of circuits and many human-centric decisions and operations which can be prone to error. Line fault indicators have a safety benefit in reducing the number of physical interactions field staff need to conduct with the network. Whilst difficult to quantify, the safety aspect of line fault indicators is a widely acknowledged benefit.

#### 6.10.4.5 Risk and Uncertainty

As discussed, the optimal configuration and location of line fault indicators is a critical success factor for such investments. Complexity of the localised network, travel time and propensity to outages all need to be considered when planning installation of the equipment. Figure 22 demonstrates the sensitivity of the project success to the input assumptions of fault rate, customers affected and time saved.

*Figure 21: Line Fault Indicator Benefit Assumption Sensitivity*




Assumptions around sensitivity of the number of faults or time saved cause the same behaviour in NPV, customers benefited impacts the NVP only slightly differently. In all cases the NPV becomes negative if one of the three variables falls to 90% of the assumed input value. Given this sensitivity, the optimal location of the indicators is imperative for a positive benefit.

# 7. Conclusions and Recommendations

Overall we find the scope and costs of the Ausgrid network innovation program reasonable. The uncertainty and sometimes novel approach that these types of project represent do not easily lend themselves to the *ex-ante* regulatory approach, where expenditure must be nominated up to six years in advance. The inevitably technology-centric nature of innovative electricity network projects present a challenge in conducting rigorous cost benefit analyses with a lead time often much greater than technology evolution cycles. Nonetheless, we find that the information provided by Ausgrid is as comprehensive and considered as can be expected within the constraints of the regulatory framework. A large proportion of the expenditure has hosting capacity benefits for consumers and other market benefits.

We consider some of the benefit forecasts are conservative and that externalities are, in some cases, not exhaustively addressed. For example, there is limited environmental benefit consideration. There are some specific examples where the scope of benefits could also be expanded. For example, the line fault indicator project definitely has safety benefits for field technicians, albeit these can be difficult to quantify. Overall we consider that the conservative nature of the CBA is appropriate given the uncertainty inherent in many of the projects.

We believe that there is a degree of interdependency in the network visibility projects, both within this program and with the ADMS project. Interdependency can be an advantage where those projects become greater than the sum of their parts, but if not managed effectively can become a disadvantage. Accordingly, we recommend that these projects are governed in a coordinated manner to avoid duplication and leverage any synergy that may become apparent during execution.

We believe that Ausgrid's engagement with customers around the network innovation program and its decision to quarantine the capital associated with the program from the Capital Expenditure Sharing Scheme are both positive signs of intent to provide long term consumer benefits. Ausgrid also provided us with draft documentation regarding a proposed Network Innovation Advisory Committee (NIAC), which we consider a positive development to ensure customers remain engaged with through the prioritisation of expenditure and execution of projects and also that progress, results and learnings are tracked and reported over time.

We believe the learnings from international experiences are worth consideration by Ausgrid and the AER, in particular:

- Collaboration.
- Transparency.
- Accountability.
- Transition to business as usual.

Each of these points is explored further following.

## 7.1 Collaboration

Innovative projects and research and development efforts are limited in effectiveness if conducted in a vacuum. Seeking feedback and input from a wide range of stakeholders – customers, academic institutions, vendors and peers – costs very little but can have profound impact on the success of innovation. The evolution of the innovation stimulus in the UK under Ofgem has led to the development of a Smarter

Networks Portal and Network Innovation Portal to foster collaboration and Ofgem's expectations for the Network Innovation Allowance and Network Innovation Competition are that networks collaborate.

> *"As part of the NIC and NIA, we expect the network companies to collaborate with each other and other parties. To help do this, we required the network companies to develop a Collaboration Portal, which directs potential collaborators to network innovation resources, documents, and contacts within the network companies for potential partners to submit project ideas."*
>
> Ofgem, 2016, Ofgem: Innovation and Regulation, page 20, London.

The DISCERN project in the European Union is another example of positive collaboration, where five networks, two vendors, three research institutions and a consultancy firm formed a consortium to trial and test innovative grid technologies, intelligence and ideas in different network environments.

In Australia, projects like the Open Energy Networks (OpEN) are emerging to encourage collaboration and partnering to solve challenges rising from increasing penetration of Distributed Energy Resources (DER).

We understand that Ausgrid is, or intends to, partner with various research institutes, vendors and other industry stakeholders for specific projects. We also observe that "collaborative opportunities" is one of the seven principles of the NIAC draft terms. We encourage Ausgrid to expand involvement in the NIAC to other networks, researchers and vendors when and as appropriate.

## 7.2 Transparency

Transparency in the reporting of innovation project status, progress and results should be considered a given within the regulatory structures that Ausgrid operates in. However Ausgrid should also be transparent in the learnings and data that result from the program. We are encouraged to learn that Ausgrid intends to share data such as that generated by the network insights project where confidentiality, privacy and security policies allow. The OpenLV project in the UK makes available substation data from parts of Western Power's network for the community to elicit novel ideas regarding the use of the data for customer benefit.

Customers pay for these projects and ultimately benefit, and therefore must be considered the custodians of the knowledge and products that are generated.

> *"Facilitating knowledge transfer is one of the key principles of the NIC. Ultimately, customers are funding the relevant work and it is a requirement of the NIC that the learning generated be disseminated as effectively as possible to ensure that all Network Licensees, and therefore all customers, are able to benefit from the Projects."*
>
> Ofgem, 2017. Electricity Network Innovation Competition Governance Document v3.0, London.

## 7.3 Accountability

86% of Ausgrid's proposed Network Innovation Program costs are incurred between 2020 and 2024 whilst 73% of the forecast benefits will occur from 2025-29. Where benefits are realised, there should be appropriate adjustments made to forecasts in future periods. The implementation of the Network Innovation Advisory Committee provides an opportunity for more detailed and transparent examination of costs and benefits throughout the regulatory period. In addition, Ausgrid has proposed that capex linked to the Network Innovation Fund be excluded from the CESS – this reduces incentives for Ausgrid to inflate the costs of the proposed solutions.

## 7.4 Transition to business as usual

Research projects and trials often encounter hurdles in the transition from experiment to incorporation. Whether the status quo is too set to challenge, funding is absent or risk appetite dissolves over time, technical change in a mature industry is difficult. The current Ausgrid innovation program has some links back to the Smart Grid, Smart City program of trials. Whilst the results of that program are still used by researchers to this day, the technologies of ten years ago that were relevant to Smart Grid, Smart City have moved on. It is important to keep momentum behind technology projects in early stages. As mentioned in this report, the UK LCNF is yet to realise benefits beyond its costs, and whilst reports suggest it will ultimately yield benefits of more than 4.5 times its cost, that figure is at risk of dilution with the passage of time as new technology makes the old redundant.

> *"Incumbent energy technologies or systems tend to have institutions, infrastructures, and policies that support them, providing barriers to entry for new technologies (sometimes called lock-in or path dependence). There is also a famous valley of death between the invention phase of innovation and the deployment phase. This valley is really two valleys, because there are often difficulties moving from R&D to demonstration (which is expensive), and then again difficulties taking a proven technology to the marketplace during the early deployment phase."*
>
> Grubler, A., et al., 2012. Policies for the Energy Technology Innovation System (ETIS), Global Energy Assessment – Toward a Sustainable Future. Cambridge University Press, Cambridge.

We consider that the Ausgrid NIAC should retain responsibility for the innovation projects well beyond the trial stage and until the benefits have been transitioned into business as usual.

A summary of our review findings is provided in Table 23 and where we have identified an area of concern or potential improvement, our specific recommendations are outlined in Table 24.

**Table 23: Innovation Program Review Summary**

| Project | Justification | Demand Forecasts | Unit Rates | Assumptions | Costs | Benefits | Risk and Uncertainty |
|---|---|---|---|---|---|---|---|
| Advanced Voltage Regulation | Reasonable | Reasonable | Reasonable | Reasonable | Reasonable | Conservative | Sensitive |
| Network Insight Program | Reasonable | Reasonable | Reasonable | Reasonable | Reasonable | Reasonable | Reasonable |
| Fringe of Grid Optimisation | Reasonable | Reasonable | Reasonable | Reasonable | Difficult to assess | Reasonable | Reasonable |
| HV Microgrid Trial | Reasonable | Reasonable | Reasonable | Reasonable | Difficult to assess | Conservative | Sensitive |
| Advanced EV Charging Platform Trial | Reasonable | Reasonable | Reasonable | Reasonable | Reasonable | Conservative | Sensitive |
| Grid Battery Trials | Reasonable | N/A | Reasonable | Sensitive | Reasonable | Conservative | Sensitive |
| Portable All-in-One Off-Grid Supply Units | Reasonable | N/A | N/A | Reasonable | Reasonable | Reasonable | Sensitive |
| Self Healing Networks | Reasonable | N/A | N/A | Reasonable | Reasonable | Reasonable | Sensitive |
| Dynamic Load Control | Reasonable | Reasonable | Reasonable | Reasonable | Reasonable | Conservative | Reasonable |
| Asset Condition Monitoring | Reasonable | N/A | Reasonable | Conservative | Reasonable | Conservative | Sensitive |
| Line Fault Indicators | Reasonable | N/A | Reasonable | Reasonable | Reasonable | Reasonable | Sensitive |

A rating other than reasonable does not necessarily indicate an adverse finding, rather it could indicate:

- An opportunity to, for example, expand the scope and scale of benefits.
- An indication of a project more exposed to changes in exogenous factors or sensitive to variation in input assumptions.
- A lack of information available at this stage.

**Table 24: Specific Project Recommendations**

| Project | Reason for Rating | Recommendation |
|---|---|---|
| Advanced Voltage Regulation | Customer benefits (VCR) are not included in the CBA. NPV is also sensitive to location attributes. | Consider including VCR benefits in the CBA for the business case stage. Include a mechanism for NIAC decision making for site analysis and selection for duration of project. |
| Fringe of Grid Optimisation | Detailed cost build up not possible until site selection and detailed specification. | Finalise site location early and develop detailed costings in the project business case. |
| HV Microgrid Trial | Detailed cost build up not possible until site selection and detailed specification. Environmental benefits not included. Sensitive to input assumptions. | Finalise site location early and develop detailed costings in the project business case. Consider environmental benefits. Consider location to ensure feeder outages avoided are material enough for NPV positive project. |

| | | |
|---|---|---|
| Advanced EV Charging Platform Trial | There is scope to expand the consideration of benefits to tariff information, network stability and charging station location optimisation. A low EV uptake scenario will also lead to a negative NPV. | Consider broader benefits at business case stage and monitor changing EV uptake forecasts. Take a real options approach to the execution of the project where possible to minimise sunk costs if the project becomes unviable. |
| Grid Battery Trials | Maintenance and reliability benefits not included. Customer accessibility benefits not included. Alternative deferral periods could also be considered. | Expand scope of benefits at business case stage and include options for different deferral/relocation periods. |
| Portable All-in-One Off-Grid Supply Units | NPV is sensitive to actual use case of units and means of prioritising solution. | Develop a set of prioritisation criteria to be used in determining location and deployment use case (e.g. during outage, planned works, etc). |
| Self Healing Networks | NPV is sensitive to site selection. | Ensure NIAC remains involved in the selection of sites and monitoring of costs and benefits as the project progresses. |
| Dynamic Load Control | Externalities (customer benefits) not included in CBA | Include customer benefits in CBA for business case stage. Ensure appropriate ongoing NIAC oversight during execution/rollout. |
| Asset Condition Monitoring | NPV is sensitive to location selection. | Ensure that business case includes analysis of optimal site locations to maximise deferral benefits. |
| Line Fault Indicators | Project outcomes are sensitive to actual fault rate, time saved and customers benefitted. | Include analysis of optimal location and number of indicators in business case prior to execution. |

# Appendices

# Appendix A – Terms of Reference

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| Draft A | O Skelding | J Blair | JB | Jamie Blair | JB | 02 Jan 19 |
| Final | Oliver Skelding | Jamie Blair | JB | Jamie Blair | JB | 04 Jan 19 |

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