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MODELLING THE IMPACT OF EMBEDDED GENERATION ON NETWORK PLANNING

Australian Energy Market Commission | 29 August 2016

Modelling the Impact of Embedded Generation on Network Planning

Client: Australian Energy Market Commission (AEMC)

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Table of Contents

List of Tables

List of Figures

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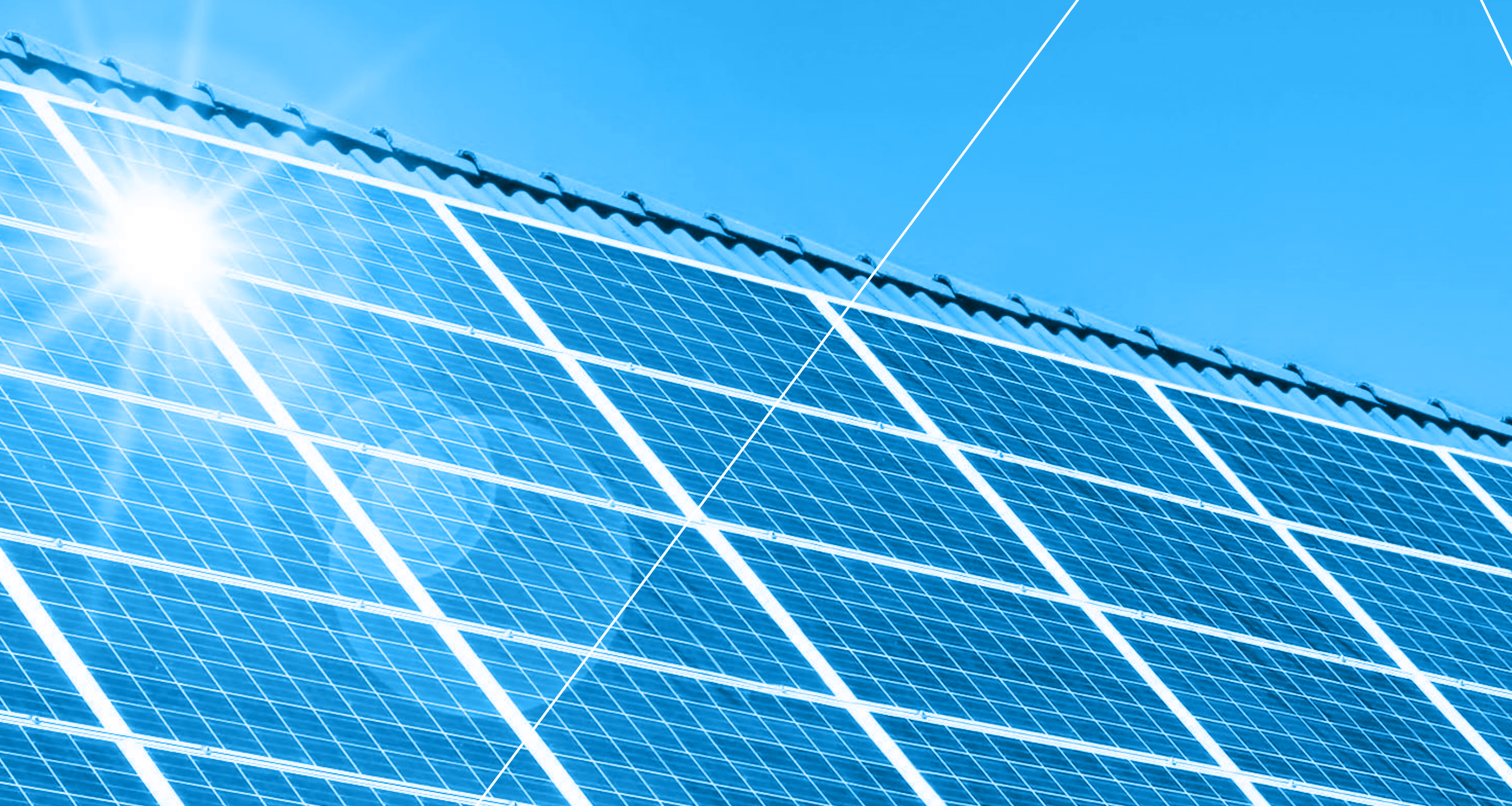
EXECUTIVE SUMMARY



Executive Summary

The Australian Energy Market Commission (AEMC) is currently assessing a rule change request in relation to the introduction of Local Generation Network Credits (LGNCs), as submitted by City of Sydney, Total Environment Centre and the Property Council of Australia. As part of this assessment process, the AEMC engaged AECOM to undertake analysis and modelling of the impacts that the introduction of LGNCs may have on network planning, costs and investment. The modelling showed that, across three case studies, introducing a LGNC had a negligible impact on the frequency and scale of peak demand. Furthermore, the modelling did not demonstrate that the introduction of LGNCs could lead to any deferral of network investment, while the Net Present Cost of paying LGNCs to embedded solar generators varied from $1 million to $19 million depending on the case study.

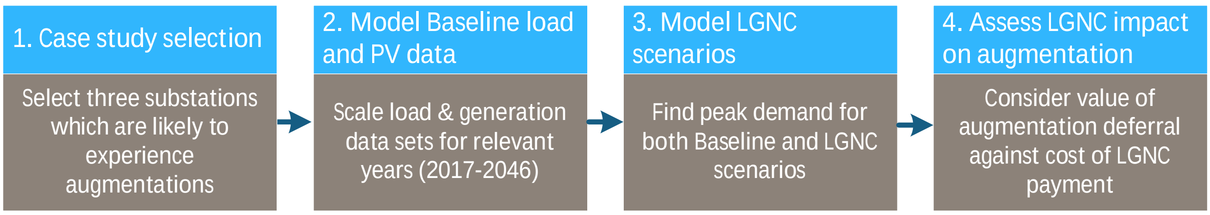
It is important to note that the analysis only considered solar PV as it was forecast to be the main beneficiary of LGNC payments according to analysis by Marsden Jacob for the AEMC [1].

The findings and results of the analysis undertaken in this report are limited by a range of factors including the accuracy of inputs, modelling assumptions and simplifications to the distribution network planning process. The results should only be interpreted within the context of these limitations. In addition, AECOM's analysis should not be taken to pre-judge the respective DNSPs' investment decisions with regard to the three case studies, and should not be used for any purpose other than assessing the costs and benefits of the LGNC rule change.

Modelling Approach

This report investigates the impact of additional distributed solar PV installations driven by an LGNC payment for three substation case studies. AECOM's approach is provided in Figure 1 below.

Figure 1 Overview of AECOM's approach



Each of the selected substations are likely to require a demand-driven augmentation within the study period (30 years). By considering case studies with expected augmentation needs, the analysis focuses on situations in which LGNCs are most likely to provide savings by deferring investment in the network. In other parts of the network, the LGNC rule change would result in payments to embedded generators even where there is no network saving. The three case studies are summarised below.

Table 1 Summary of case studies

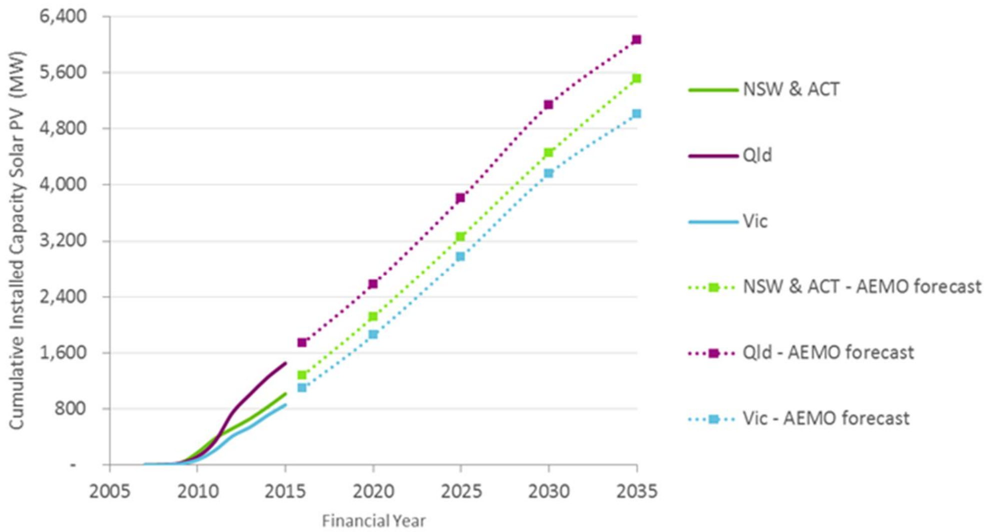
	Belconnen Zone Substation	Flemington Zone Substation	Emerald Zone Substation
State	ACT	Victoria	Queensland
DNSP	ActewAGL	Jemena	Ergon Energy
Number of customers	11,000	15,000	8,700
Customer type	Urban	Urban	Remote
Current peak demand	55 MVA	34 MVA	37 MVA
Projected year of augmentation (Baseline)	FY2019	FY2023	FY2033

Following selection of the three case studies, AECOM developed a Demand Profile Model. This model utilised publically available inputs (e.g. substation load data, Annual Planning Reports, RIT-D reports, solar irradiation data from the Bureau of Meteorology) to synthesise future 30-minute demand profiles under the Baseline scenario and the LGNC scenario. The Demand Profile Model measured the impact of additional LGNC solar on maximum demand across the three case studies and determined whether the existence of the LGNCs could reduce demand sufficiently to defer network investment. Any augmentation deferral was then valued in Net Present Value terms against the cost of paying LGNCs.

LGNCs Scenario vs. Baseline Scenario

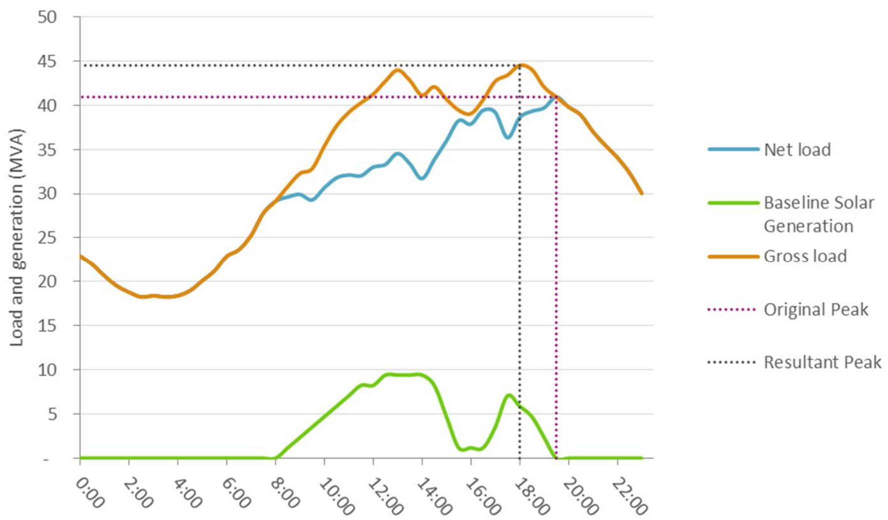
The impact of the LGNC rule change was measured relative to a Baseline scenario. A key input of the Baseline scenario was AEMO's state-based solar PV uptake projections from the 2016 National Electricity Forecasting Report. The significant growth in solar PV forecast by AEMO resulted in large amounts of solar PV in the Baseline scenario, while the LGNC scenario incentivised additional solar PV.

Figure 2 Historic and projected rooftop solar PV uptake across the NEM [2] [3]



Four separate sensitivities were modelled for the additional uptake of solar PV under the LGNC scenario; however it was found that the additional solar incentivised through LGNCs had minimal impact on peak demand. This is because the peak demand period was found to shift away from sunlight hours as more solar PV was installed in the Baseline scenario. Figure 3 demonstrates this result where gross load peaks at 6:00pm. The introduction of Baseline solar PV shifts the net load peak to 7:30pm. Once the peak is shifted outside sunlight hours, additional solar PV adds no further value in reducing the peak demand on this day.

Figure 3 Flemington zone substation– load profile demonstrating peak shifting



When setting up the analysis, AECOM considered three separate demand profiles for each site: Data Sets 1, 2 and 3. Each of the Data Sets was based on a different year of historic demand and solar generation data (FY13, FY14 and FY15) to capture some of the natural variation in demand profiles. Using three data sets also provided a broader picture of the reliability of LGNC solar providing a reduction in peak demand with each Data Set potentially exhibiting peaks at different time periods.

For all three case studies, the level of peak demand reduction from additional solar was small (less than 0.35MVA) and was found to be insufficient to defer investment in the targeted constraint year. This is summarised in Table 2.

Table 2 Summary of deferral observed for each site in their respective augmentation years

	Data Set 1	Data Set 2	Data Set 3
Belconnen ZS	No deferral	No deferral	No deferral
Peak period (Baseline)	5:00pm 18 January	5:30pm 3 February	6:30pm 30 June
Peak reduction (MVA) 10% additional solar uptake	0.08	0.06	No reduction
Flemington ZS	No deferral	No deferral	No deferral
Peak period (Baseline)	7:30pm 18 November	7:00pm 28 January	6:30pm 7 January
Peak reduction (MVA) 10% additional solar uptake	No reduction	0.07	No reduction
Emerald ZS	No deferral	No deferral	No deferral
Peak period (Baseline)	7:30pm 14 January	8:00pm 4 January	5:00pm 18 November
Peak reduction (MVA) 10% additional solar uptake	No reduction	No reduction	0.09

While no deferral has been forecast, the cost of paying LGNCs is substantial, as shown in Table 3. AECOM has estimated that 2 years deferral would be required to offset the LGNC cost at Belconnen, while 5 years deferral is required at Flemington. At Emerald, the LGNC cost cannot be recovered through deferral because the LNGC cost exceeds the cost of the augmentation ($15.37 million in net present terms).

Table 3 Required deferral to offset LGNC cost – 10% additional solar PV Uptake relative to Baseline scenario

	Belconnen ZS	Flemington ZS	Emerald ZS
Cost of LGNCs (NPV)	$1.21 million	$2.04 million	$17.78 million
Calculated deferral required to offset LGNC cost	2 years	5 years	Cost cannot be recovered through deferral

Summary of Key Findings

The uptake of solar PV is forecast to be significant under the Baseline scenario (as per AEMO forecasts) and therefore the impact of solar PV on Baseline network load profiles is projected to be significant. Peak demand periods are expected to shift outside of sunlight hours. In fact, solar PV is already reducing peak demand during daylight hours and future uptake of solar PV will further shift most peak demand periods from daylight hours to the evenings. Once the peak period has been shifted in the Baseline scenario, the LGNC scenario is unable to provide further peak demand reduction.

AECOM's modelling showed that, across the three case studies, LGNCs only had a marginal impact on peak demand magnitude and frequency. Furthermore, the modelling did not demonstrate that the introduction of LGNCs could result in any deferral of network investment. It was also found that the cost of the LGNC rule change is significant. To offset this cost, the rule change would have to result in long augmentation deferrals to recover costs.

While solar PV penetrations start pushing peak periods outside of daylight hours, this does not imply that there is no future role for solar PV. Future demand management technologies including the use of battery storage could help shift load into solar generation hours. AECOM's modelling of solar-storage pairing indicated that the solar-storage system compared with stand-alone solar was better equipped to deal with the natural variation in peak demand times and better suited to reducing maximum demand that occurred outside solar generation periods.

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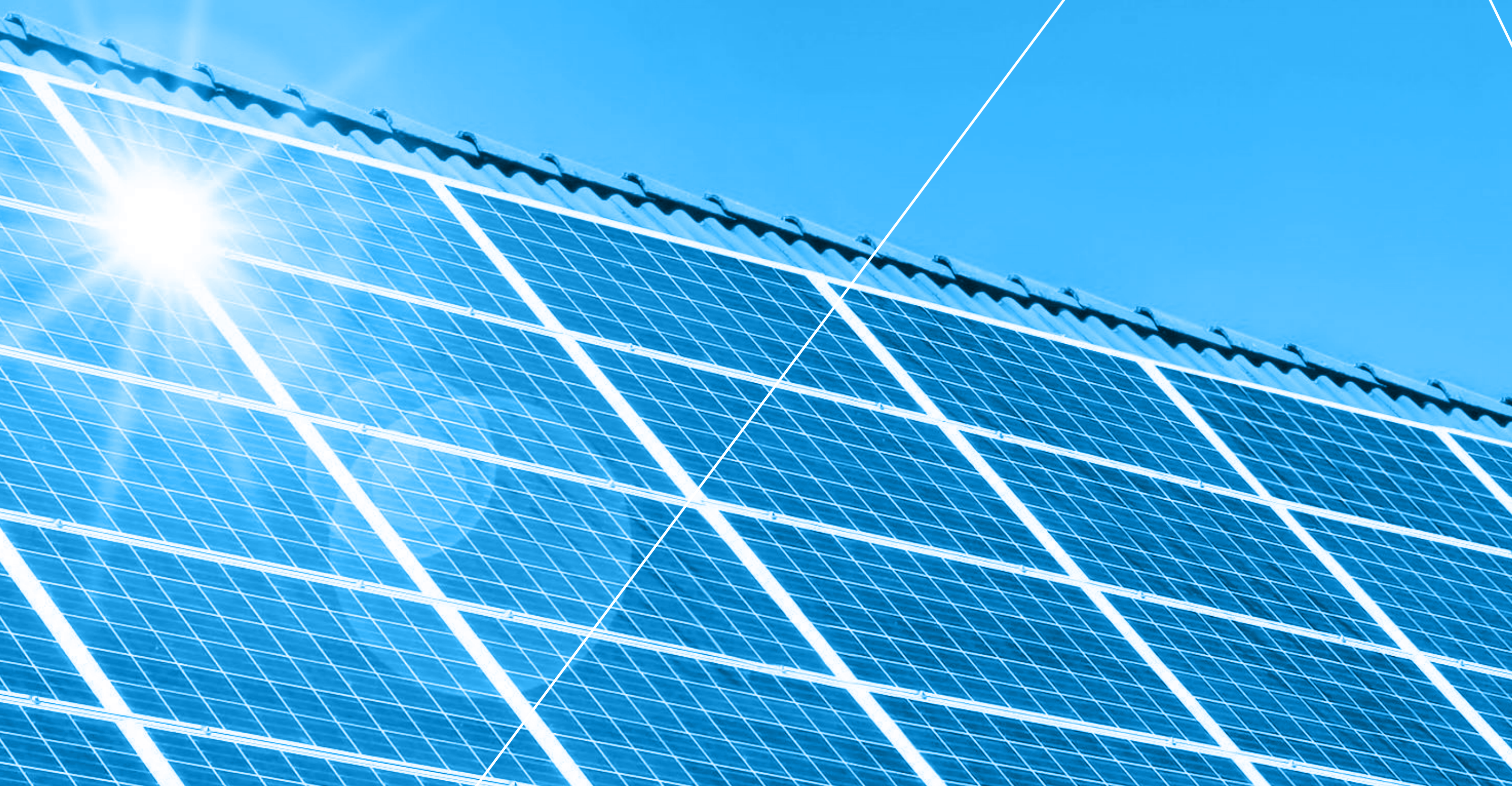
GLOSSARY



Glossary

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
Baseline	Assumed baseline level of solar capacity installed. Based on AEMO projections and scaled to individual sites.
BOM	Bureau of Meteorology
CAPEX	Capital Expenditure
DAPR	Distribution Annual Planning Report
DLF	Distribution Loss Factor
DNSP	Distribution Network Service Provider
DPM	Demand Profile Model
LGNC	Local Generation Network Credit
LGNC solar	Additional solar capacity installed under the LGNC scenario
NEM	National Electricity Market
NEFR	National Electricity Forecasting Report
NPV	Net Present Value
OPEX	Operating Expense
POE	Probability of Exceedance
PV	Photovoltaic
RIT-D	Regulatory Investment Test – Distribution
STATCOM	Static Compensator
TLF	Transmission Loss Factor
ZS	Zone Substation

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1.0 INTRODUCTION

1.0 Introduction

1.1 Background and Context

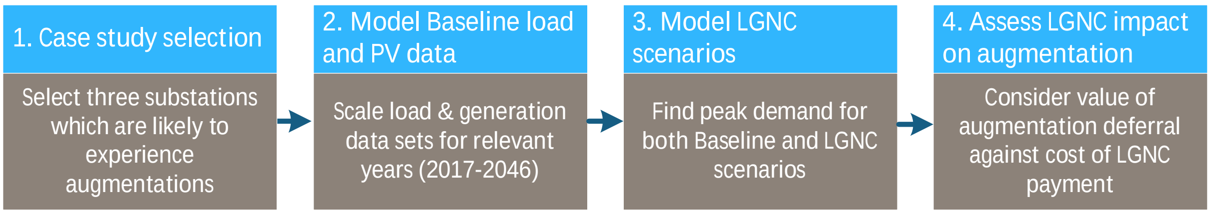
The AEMC is currently assessing a rule change request in relation to the introduction of Local Generation Network Credits (LGNCs), as submitted by City of Sydney, Total Environment Centre and the Property Council of Australia. The rule change aims to incentivise investment in embedded generation aimed at reducing maximum demand. In doing so, new embedded generators could defer investment in network assets by reducing peak demand. As a part of its assessment process, the AEMC engaged AECOM to undertake analysis and modelling of the impacts that the introduction of LGNCs may have on network planning, costs and investment.

1.2 Project Scope

The purpose of this study is to assess the impact of the introduction of LGNCs on network planning. This includes the impact on loads profile at each substation considered, as well as any subsequent value earned by deferring augmentation projects at the substation. The study focuses on three substations which are likely to require augmentation due to increasing electricity demand over a 30-year forward-looking period. AECOM was requested to focus on solar, which is forecast by Marsden Jacob [1] to be the main beneficiary of LGNC payments.

The project scope is summarised in the figure below.

Figure 4 Overview of project scope



1.3 Limitations and Assumptions

The findings and results of the analysis undertaken in this report are limited by a range of factors including the accuracy of inputs and assumptions which have been made in relation to the modelling.

In providing analysis for the three selected case studies assessed in this report, it is acknowledged that the outcomes and results of the analysis for each case study may not necessarily be representative or typical of outcomes for other potential sites or projects.

In completing this report, AECOM has made the following assumptions:

- This study is designed to better inform the potential impact of an LGNC on deferring network investment. All conclusions should be understood in the context of the broader limitations and assumptions of this report.
- AECOM has made simplifications to the network planning and investment decision frameworks. Our assumptions regarding the investment decision triggers are stated separately for each site.
- AECOM has only considered the impact of solar PV. No other embedded generation type has been captured, except for consideration of the impact of battery storage paired with solar PV.
- AECOM has assumed future load profiles are consistent with current profiles. The impact of evolving customer behaviour and changing technology has not been considered.
- LGNC pricing rates and structures were provided by the AEMC as an input based on work completed by Marsden Jacob [1]. AECOM has not verified these inputs.
- AECOM has completed its modelling in 30 minute increments, which does not fully capture the intermittent nature of solar PV.
- Distributed solar PV has the technical capability to provide reactive power into the network. However, AECOM has not modelled the benefit of solar PV providing reactive power.

- When forecasting augmentation investment decisions, AECOM has taken a simplified approach which does not forecast probability of exceedance (POE) demands, estimate duration of capability exceedance, or place specified value on forecast customer outages.
- AECOM has relied on DNSP peak demand forecasts and assumed that these forecasts account for solar uptake. While it is not clear what levels of solar PV uptake have been accounted for in the DNSP peak demand forecasts, AECOM has assumed that they are comparable with the uptake rates proposed in AECOM's National Electricity Forecasting Report 2016.
- AECOM has not quantified any reductions to transmission or distribution loss factors (TLF and DLF) – this was excluded from our scope.
- The cost of administrating the LGNC scheme has been excluded.
- The cost of facilitating high penetrations of solar PV has not been quantified. However, AECOM has completed analysis quantifying the level of reverse flow and commentary on some of the challenges of integrating high penetrations of solar PV.
- Only constraints at the substation level have been included in this analysis. Downstream feeder constraints were not considered at this time, as information on feeder loading was not readily available.
- AECOM has used Bureau of Meteorology satellite irradiation data to develop historical solar generation profiles that are coincident with historical demand.
- AECOM has used three data sets to mitigate against the probabilistic variations that occur in the source data; however the use of three data sets is still highly limited in its ability to capture the natural variance of demand behaviour and its coincident solar generation.

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2.0 CASE STUDY SELECTION

2.0 Case Study Selection

2.1 Project Selection

AECOM has selected 3 case studies for analysis in this study. In selecting its case studies, AECOM has sought to make selections that represent different types of network while also being broadly representative of diversity inherent within electricity networks.

AECOM's selection criteria are shown in Table 4 below.

Table 4 Network augmentation case study selection criteria

Criteria	Requirement
Materiality	Value greater than $3 million
Network variation	Three case studies that provide both geographical diversity and diversity of customer type (i.e. urban vs. rural)
Temporal variation	Three separate time horizons: - Current regulatory period - Less than 10 years - Greater than 10 years
Availability of information	30-minute historic load data Maximum demand forecasts Detail of constraints and resolutions (common in RIT-D reports)

2.1.1 Shortlisting

AECOM's approach was to shortlist substations that were identified to have future capacity constraints. AECOM then ensured that sufficient data was available (e.g. historical load data, demand forecasts, asset information) and selected three case studies from the shortlist that were deemed suitable. The final selection ensured that substations were from different geographies (i.e. different states) and contained a mixture of rural and urban customer types.

As potential case studies were shortlisted, it was noted that substations undergoing the Regulatory Investment Test – Distribution ("RIT-D") had substantially more detail available than other network assets, which would help the accuracy and reliability of our analysis. This led to AECOM strategically targeting network assets that had RIT-D documentation available. Supplementary data was often found in Distribution Annual Planning Reports.

AECOM has sought to include at least one substation from each of the largest NEM regions in its shortlist. Projects in Queensland, Victoria and South Australia were identified by reviewing projects progressing through the RIT-D process in selected networks. However, AECOM did not identify any suitable projects in NSW through the RIT-D reports, or through reviewing data available in the Distribution Annual Planning Reports (DAPR).

The shortlist included the following projects:

- Queensland
  - Emerald 66/22kV Zone Substation
  - Malchi 66/11kV Zone Substation
- NSW and ACT
  - Bourkelands 66/11kV Zone Substation
  - Attunga 66/11kV Zone Substation
  - Belconnen 132/11kV Zone Substation
- Victoria
  - Flemington 66/11kV Zone Substation

  - Notting Hill 66/22kV Zone Substation
- South Australia
  - Bordertown substation 33/11kV Zone Substation.

Projects identified under the RIT-D process address network constraints that typically require a response within 5 years, whereas AECOM needed to identify two projects with constraint horizons longer than 5 years (i.e. 5-10 years and 10+ years). Nonetheless, RIT-D projects were still suitable for this analysis if long term constraints could be identified (i.e. constraints which are expected to occur beyond implementation of the immediate RIT-D solution). This requires an assumption on the resolution of the RIT-D process, which determines a new capacity constraint that can be exceeded in the longer term future.

2.1.2 Project Analysis

Table 5 provides an overview of the key characteristics of each project that was shortlisted, including a description of the customers, the constraint's required investment date (i.e. time horizon), cost estimates for the preferred network augmentation option, and a brief description of the suitability of the project for use as a case study.

Table 5 Assessment of short-listed case studies [4] [5] [6] [7] [8] [9] [10]

State	Asset & Owner	Location	Customers No. & Type	Augmentation Date	Current Peak Demand	Augmentation Capital Cost	Existing Solar Penetration	Comment	Recommendation
Current Regulatory Period (2014 – 2019)									
QLD	Malchi Substation (66/11kV) Ergon Energy	Gracemere, QLD (near Rockhampton)	5,388 93% residential (69% by load)	2018	16 MVA	$7 million	22%	- High proportion of residential customers	Not preferred as alternative Qld site (Emerald) selected due to favourable project timeframe (10+ years)
	Emerald Substation (66/22kV) Ergon Energy	Remote town (300km inland from Rockhampton)	8,700 Mix of residential, commercial and industrial	2020 (initial constraint)	37 MVA	$6.5 million (in 2020)	23%	- Initial constraint is a voltage constraint (whereas study focus in on capacity constraint) - Assuming the preferred RIT-D option is implemented, a new capacity constraint will occur in 2033 which was selected (refer below).	Considered as suitable case study for 2nd constraint (~2033).
ACT	**Belconnen Substation** **(132/11kV)** **ActewAGL**	Northern Canberra, ACT	11,000 Mix of residential, commercial and industrial	2020	55 MVA	$13 million (DAPR)	14% (4.01 MW across 1557 installations)	- Good detail is available on this project in ActewAGL's DAPR - Few promising alternatives in the NSW/ACT region - RIT-D process is proposed to commence next year	Deemed a suitable case study ✓
SA	Bordertown Substation (33/11kV) SA Power Networks	Bordertown, SA	3,000 Mainly residential with some commercial and agricultural load	2013 (implemented)	14 MVA	$10 million (RIT-D)	33%	- Project is already completed	Not preferred as augmentation has already occurred

State	Asset & Owner	Location	Customers No. & Type	Augmentation Date	Current Peak Demand	Augmentation Capital Cost	Existing Solar Penetration	Comment	Recommendation
Up to 10 years (2020 – 2027)									
NSW	Bourkelands Substation (66/11kV) Essential Energy	Wagga Wagga, NSW	N/A	2023	10 MVA	N/A	17%	- Poor access to asset information including constraint detail, proposed solutions and costing information - Number of customers not known - Very few future constraints identified in NSW	Not preferred due to lack of suitable publicly available data
VIC	**Flemington Substation (66/11kV)** **Jemena**	West Melbourne, VIC	15,000 Mix of residential, commercial and industrial	2023 (2nd constraint)	34 MVA	~$10 million (in 2022) (RIT-D)	8%	- Assuming the preferred RIT-D option is implemented, a new capacity constraint will occur in 2023 which may be worthwhile considering as a potential future project - Preferred network option is to upgrade the 11kV transformer cables and 11kV switchboards, and install a third 11kV switchboard (in the existing switch-room building) in at an estimated cost of $7.0 million - This would increase the capacity to 41MVA, which will likely be exceeded within the 10 year timeframe. Following this, installation of a 3rd transformer appears to be a reasonable network solution	Deemed a suitable case study ✓

State	Asset & Owner	Location	Customers No. & Type	Augmentation Date	Current Peak Demand	Augmentation Capital Cost	Existing Solar Penetration	Comment	Recommendation
VIC	Notting Hill Substation (66/22kV) United Energy	Outer South-East Melbourne, VIC	3,800 80% residential (20% by load, i.e. 80% commercial/ industrial)	2025 (2nd constraint)	45 MVA	N/A	8%	- Initial constraint is set to be resolved in 2017, leaving little time for the LGNC incentive to have a material impact - The current preferred solution (for 2017) is to add one transformer which will increase n-1 capacity to ~66-73MVA (depending on interpretation). This capacity is forecast to be exceeded in ~2025, which may be suitable for 2020-2027 timeframe	Not preferred due to lack of detail on future constraint solution options
Beyond 10 years (2027+)									
QLD	**Emerald Substation (66/22kV)** **Ergon Energy**	Remote town (300km inland from Rockhampton)	8,700 Mix of residential, commercial and industrial	2033 (2nd constraint)	37 MVA	$40 million (in 2028) (RIT-D)	23%	- Assuming the preferred RIT-D option is implemented, a new capacity constraint will occur in 2033 which may be worthwhile considering as a potential future project - Information in current RIT-D can help forecast long term future constraint - Cost of long term constraint (i.e. new upstream 66kV feeder Blackwater to Emerald) is estimated in the RIT-D ($39.5 million)	Deemed a suitable case study ✓

State	Asset & Owner	Location	Customers No. & Type	Augmentation Date	Current Peak Demand	Augmentation Capital Cost	Existing Solar Penetration	Comment	Recommendation
NSW	Attunga Substation (66/11kV) Essential Energy	Near Tamworth, NSW	N/A	2028	3 MVA	N/A	19%	- Low cost upgrade (potentially less than $3 million) - Poor access to asset information including constraint detail, proposed solutions and costing information - Number of customers not known	Not preferred due to poor access to data and small nature of project

The final selection of case studies incorporated a remote substation in Queensland (Emerald ZS, with a 10+ year augmentation timeframe), and two urban zone substations which include Belconnen ZS (augmentation inside the current regulatory period) and Flemington ZS (augmentation in 5-10 year timeframe). This selection provided a favourable mix of geographic and network diversity, while also enabling beneficial access to data.

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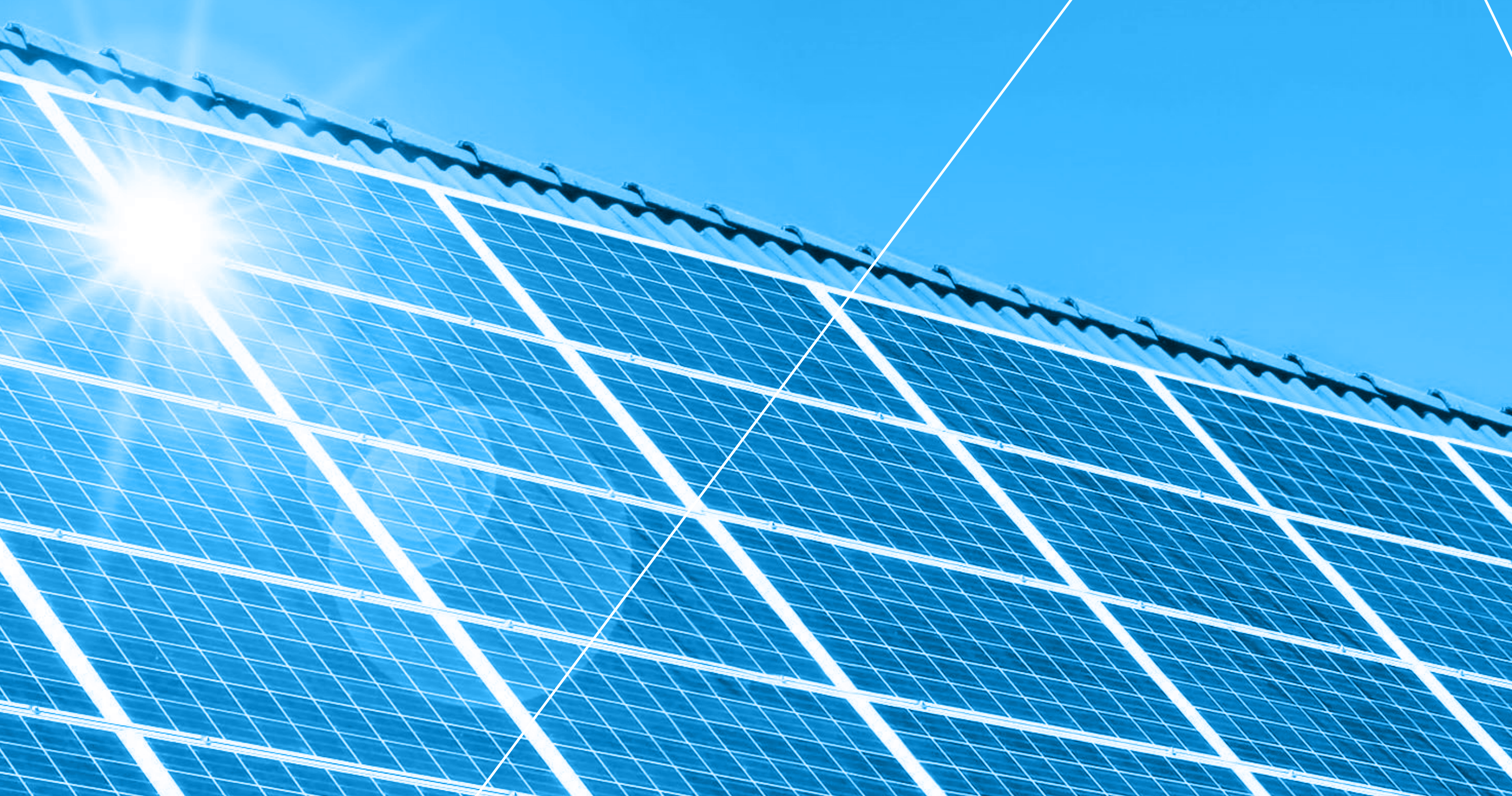
3.0 CASE STUDY OVERVIEWS



3.0 Case Study Overviews

Using the shortlist process above, AECOM identified three preferred sites which met the selection criteria. The three projects (Emerald, Belconnen and Flemington zone substations) are described in more detail below.

Introductory note:

- The network planning procedures vary in different states and for different asset classes.
- We have made simplifications and assumptions in order to best emulate the planning process for each project.

3.1 Case Study 1: Belconnen Zone Substation (ActewAGL)

3.1.1 Background

Situated in Canberra's north, Belconnen Zone Substation (ZS)supplies power to approximately 11,000 residential and commercial customers, with notable customers including the Belconnen Town Centre, Calvary Hospital, University of Canberra, Canberra Institute of Technology, and the Australian Institute of Sport. The substation consists of two 132/11kV 30/55 MVA transformers, each with a cyclic rating of 63MVA. [4]

3.1.2 AECOM Approach

Increasing local demand has led to an imminent constraint at Belconnen ZS. ActewAGL has identified the constraint in its Annual Planning Report and has flagged a need for augmentation. Through the RIT-D process, ActewAGL has investigated 4 options to resolve the constraint. The preferred option is the installation of a third transformer by June 2020. Installation of a third transformer would provide sufficient firm capacity to meet the forecast demand and help maintain N-1 security of supply as required by ActewAGL's planning criteria. ActewAGL is planning on commencing a RIT-D process in July 2017 to identify potential non-network solutions. [4]

AECOM has selected this case study as a short term (less than 5 year) augmentation option for investigation of the ability of LGNCs to defer the augmentation. The peak demand forecast and augmentation solutions recommended by ActewAGL have been used in establishing the Baseline CAPEX expenditure in AECOM's cost modelling. [4]

3.1.3 Constraint Description

Belconnen ZS experiences similar peak demand levels in both summer and winter. To date, the largest peak demand event was 58MVA in February 2014 and peak demand is forecast to grow due to new residential developments in the area. Maximum demand is forecast to exceed the summer N-1 cyclic rating (63 MVA) within the next 5 years [4]. AECOM has defined the constraint based on the transformer's cyclic rating under N-1 conditions.

Table 6 Summary of N-1 rating constraints at Belconnen ZS [4]

Details	Value	Comment
Current peak demand	58MVA	February 2014
Demand constraint (N-1)	63MVA	Transformer cyclic rating used ActewAGL forecasts the constraint for 2017 and is planning to have the resolution implemented by 2020

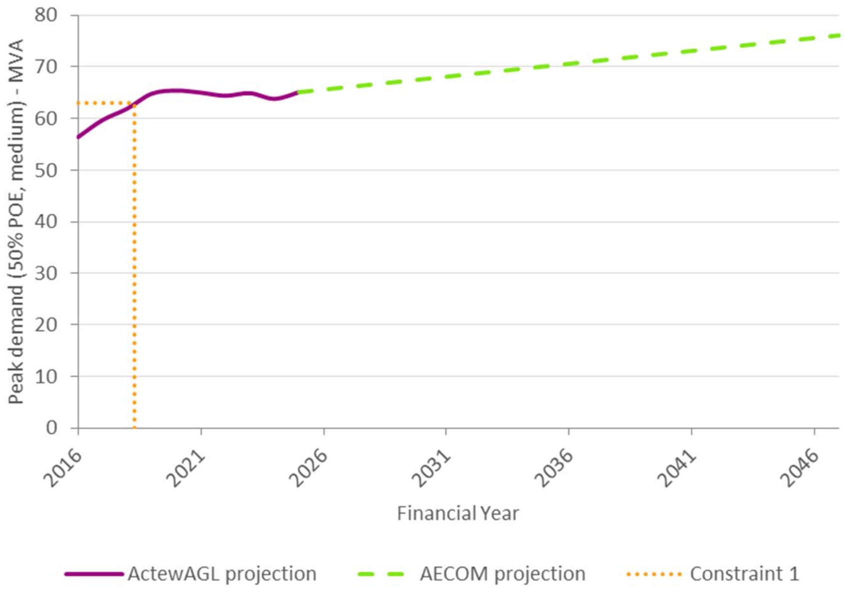
ActewAGL's proposed constraint resolution will not be completed until June 2020. Before this point, ActewAGL proposes to manage peak demand by transferring load to adjacent zone substations.

3.1.4 Demand Forecast

Figure 5 below shows ActewAGL's projection of maximum demand at Belconnen ZS to 2025 and AECOM's extrapolation to 2047. ActewAGL is forecasting rapid growth in peak demand until 2020. After this point, demand growth is expected to return to a slower growth rate.

Beyond 2025, AECOM has forecast peak demand to continue to grow at a rate of 0.5 MVA/yr for the Baseline scenario.

Figure 5 Belconnen ZS summer peak demand forecast (50% POE, medium) (Source: AECOM based on ActewAGL, [11])



3.1.5 Investment Decision Details

AECOM's approach to modelling investment decisions is outlined in Section 4.3. It focuses on the use of an investment trigger when the modelled peak demand exceeds the substation capability. In this case study, it is clear that ActewAGL intends to maintain N-1 redundancy at the substation. As such, substation constraints are considered in N-1 conditions.

ActewAGL's preferred network solution is to install a third transformer by June 2020. The timing of this investment is most closely linked to the intersection of 50% POE peak demand forecasts with the transformer cyclic rating under N-1 conditions (63MVA). This intersection occurs in 2019, compared to the planned solution being fully delivered by June 2020. Nonetheless, this method was deemed to be a sufficiently accurate approximation for the purposes of this study.

Table 7 Summary of augmentation decision and cost – Belconnen ZS

Item	Description	Comment
Initial substation constraint	63 MVA	- Constraining equipment is transformer - Constraint at transformer cyclic rating under N-1 conditions
Augmentation	Installation of a third transformer	- Include new bays, a third 11kV switchboard (in new building) and associated protection and control equipment
Augmentation cost	CAPEX: $12.62 million [4] OPEX: 0.1% of CAPEX	- CAPEX is spread over the 3 years preceding the constraint (25%, 50%, 25%) - OPEX estimate by AECOM
Investment trigger	When forecast peak demand exceeds constraint (i.e. 63 MVA)	Peak demand is forecast under 50% POE, medium growth scenario as per ActewAGL's Annual Planning Report
New substation constraint	126 MVA	3 transformers with 63MVA summer cyclic rating, hence N-1 capability is 2 x 63MVA

Since the new substation constraint (126MVA) far exceeds projected demand (76MVA in 2047), no further constraints are forecast within the study's 30 year timeframe.

3.2 Case Study 2: Flemington Zone Substation (Jemena)

3.2.1 Background

Located in Jemena's distribution network in Victoria, the Flemington Zone Substation (ZS) is supplied by two 66kV lines from West Melbourne Terminal Station. It consists of two 66/11 kV 20/30 MVA transformers, two 11 kV buses and ten 11 kV feeders and supplies approximately 15,000 domestic, commercial and industrial customers in the Flemington, Kensington, Ascot Vale and surrounding areas. Major customers include Flemington Race Course and the Melbourne Showgrounds.

3.2.2 AECOM Approach

Increasing local demand has led to an imminent constraint at the substation. In response, Jemena has commenced a RIT-D process and published a Stage 1 Non-Network Options Report on 21 October 2015. It is assumed that LGNCs could not be introduced fast enough to have an impact on the level of embedded generation in time for addressing the imminent constraint. Instead, AECOM has used the detail contained within the report to project a possible future constraint at the substation. AECOM has been able to use costed augmentation solutions (also provided in the Jemena report) to help form the Baseline CAPEX expenditure in our cost modelling.

3.2.3 Constraint 1 Description (2017)

The Flemington ZS capacity is limited by the 11 kV transformer cables and circuit breakers. As a consequence, the full capacity of the two existing transformers cannot be fully utilised. Currently, maximum demand of 34.2MVA already exceeds the N-1 rating of the 11kV transformer cables and circuit breakers, despite a new feeder reconfiguration (completed in November 2015) providing 6MVA additional transfer capacity (from Essendon and Essendon North zone substations) during peak demand periods [5].

Table 8 Summary of N-1 rating constraints at Flemington ZS [5], [11]

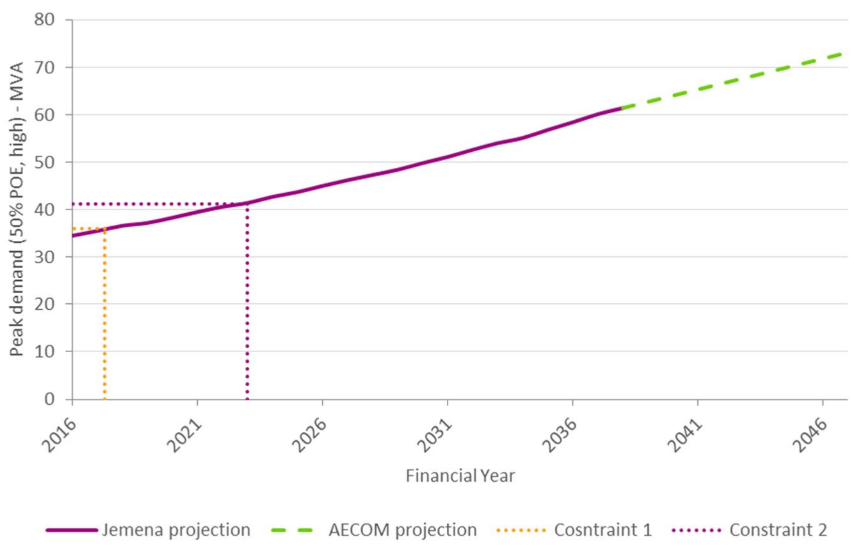
Details	Value	Comment
Current peak demand	34.2 MVA	
11kV transformer cable rating	23.9 MVA	Current constraint to be resolved in 2017
11kV transformer circuit breaker rating	27 MVA	Current constraint to be resolved in 2017
66/11kV transformer cyclic rating (summer)	34.8MVA	
Transfer capacity from Essendon ZS and North Essendon ZS	6 MVA	A new feeder reconfiguration (completed in November 2015) will provide additional transfer capacity. During peak demand periods, the transfer capacity is expected to be limited to approximately 6 MVA. [5]

Preparations for resolution of this constraint have commenced and are scheduled to be completed by November 2017. This includes upgrading the 11kV transformer cables and 11kV switchboards, and installing a third 11kV switchboard (in the existing switch-room building) at an estimated cost of $10.4 million ($4.8 million of which is deemed to be augmentation, with the remainder classified as replacement costs) [5]. The augmentation will increase the substation's N-1 capability to 40.8 MVA. This includes 34.8MVA cyclic rating of one transformer and an additional 6MVA transfer capacity from Essendon ZS and Essendon North ZS.

3.2.4 Demand Forecast

Table 9 below shows Jemena's projection of maximum demand at Flemington ZS to 2025.

Table 9 Flemington ZS peak demand forecast (summer 50% POE – high load growth scenario) [5]



AECOM has selected Jemena's high demand growth forecast (rather than the medium growth) because it prompts a second constraint within the 30 year time frame.

3.2.5 Constraint 2 Description (2023)

Following the upgrade of the 11kV transformer cables and switchboards, the Flemington ZS N-1 capability is increased to 40.8MVA. Peak demand is forecast to exceed this capability in 2023. The options to address the 2023 constraint are equivalent to the options outlined in Jemena's Stage 1 Non-Network Options Report for Constraint 1, with the exception of Option 1 (upgrading the 11kV transformer cables and 11kV switchboards), which was assumed to have been implemented to resolve Constraint 1. These include the options outlined in the table below:

Table 10 Summary of augmentation options as per Jemena's Stage 1 Non-Network Options Report in 2015

Option	Cost Estimate (2014$) [5]
Option 2: Redevelop Flemington ZS	$11.2 million
Option 3: Establish a new zone substation at alternate site	$35 million
Option 4 (preferred): Install a third 66/11kV transformer*	**$10.3 million (preferred)**

** Note: $5.6 million cost for replacing aging switchboards is excluded (only augmentation component is considered)*

Given the above cost estimates, it is likely that Option 4 would be preferable. This augmentation includes:

- installation of a new (third) 66/11 kV 20/33 MVA transformer
- installation of two 66 kV bus-tie circuit breakers
- two new bus tie circuit breakers.

Jemena stated this option would increase the N-1 rating to 47.8 MVA. However, Jemena's assessment did not account for the upgrade of the 11kV transformer cable and 11kV transformer circuit breakers, which would have already been completed when Constraint 1 was resolved. As such, the N-1 capability will increase to 69.6MVA (i.e. 2 x 34.8MVA transformers).

3.2.6 Constraint 2 – Investment Decision Details

AECOM's approach to modelling investment decisions is outlined in Section 4.3. It focuses on the use of an investment trigger when the modelled peak demand exceeds the substation capability. In this case study, it is clear that Jemena intends to maintain N-1 redundancy at the substation. As such, substation constraints are considered in N-1 conditions.

As with the constraint at Belconnen, AECOM has chosen to define the investment trigger as when 50% POE maximum demand exceeds the N-1 capability of the substation (40.8MVA for Constraint 2). It is acknowledged that this augmentation trigger definition is a simplification of Jemena's planning process; however the simplification is necessary to permit decisive triggers.

For this case study, the focus is on Constraint 2 as it is forecast to occur within the 5-10 year horizon (2023), whereas Constraint 1 is already being addressed by Jemena with work schedule to be complete in November 2017.

Table 11 Summary of augmentation decision and cost

Item	Description	Comment
Constraint 1		
Initial substation constraint	29.9MVA	- 11kV transformer cables is constraining equipment under N-1 conditions
Augmentation description	11kV transformer cable upgrade	- 11kV transformer cables - 3 x 11kV switchboards
Augmentation cost	CAPEX: $4.8 million [5] OPEX: 0.1% of CAPEX	- CAPEX is spread over the 3 years preceding the constraint (25%, 50%, 25%) - OPEX estimate by AECOM
Investment trigger	November 2017	As per scheduled completion date of preferred solution
New substation constraint	40.8MVA	
Constraint 2		
Initial substation constraint	40.8MVA	- Transformer is constraining equipment - Constraint at transformer cyclic rating under N-1 conditions - Includes an allowance for 6MVA transfer capacity during peak demand periods
Augmentation description	Install a third 66/11kV transformer	- Installation of a new (third) 66/11 kV 20/33 MVA transformer; and - Installation of two 66 kV bus-tie circuit breakers. - Two new bus tie circuit breakers
Augmentation cost	CAPEX: $10.3 million [5] OPEX: 0.1% of CAPEX	- CAPEX is spread over the 3 years preceding the constraint (25%, 50%, 25%) - OPEX estimate by AECOM
Investment trigger	When forecast peak demand exceeds constraint (i.e. 40.8 MVA)	Peak demand is forecast under 50% POE, high growth scenario as per Jemena's RIT-D Stage 1 report
New substation constraint	75.6MVA	3 transformers with 34.8MVA cyclic rating - hence N-1 capability is 2 x 34.8MVA plus an addition 6MVA transfer capacity

With the new substation capability exceeding projected demand, no further constraints are forecast within this study's 30 year timeframe.

3.3 Case Study 3: Emerald 66/22kV Zone Substation (Ergon Energy)

3.3.1 Background

Ergon Energy's Emerald 66/22kV 3 x 20MVA Zone Substation (ZS) is located in remote Queensland, approximately 270km west of Rockhampton. It supplies approximately 8,700 customers in Emerald and its adjoining rural area. The customer base is a mix of residential, commercial and industrial loads. Peak demand generally occurs in late afternoon or evening during summer. Emerald ZS receives supply from two 66kV lines, one from the H015 Lilyvale bulk supply substation, and one from the T032 Blackwater bulk supply substation. The Blackwater line also supplies the Comet 5+2MVA ZS via a tee-off. [6]

3.3.2 AECOM Approach

Increasing local demand has led to an imminent constraint at the substation. In response, Ergon Energy has commenced a RIT-D process and published a Draft Project Assessment Report in May 2016 [6].

Once this imminent constraint is resolved, it is likely that an additional future constraint will emerge in the “greater than 10 year” timeframe. As such, AECOM has targeted this long term constraint in its LGNC modelling. AECOM has used the detail contained within Ergon Energy’s report to project the future constraint at the substation.

3.3.3 Constraint 1 (2019)

The Emerald maximum demand is presently 39.7MVA and is forecast to grow by approximately 0.7MVA per annum. Despite having a combined capacity of 59.5MVA, Emerald ZS’s upstream feeders do not have sufficient capability to supply the forecast increase in load at Emerald, with voltage constraints emerging when demand exceeds 45MVA. It is noted that this constraint exists under N capability, which is the requirement nominated by Ergon Energy in its RIT-D report.

Table 12 Summary of existing N capability at Emerald ZS [6]

Details	Value
Blackwater – Emerald 66kV Feeder	23.5 MVA
Lilyvale – Emerald 66kV Feeder	36.0 MVA
Combined 66kV feeders (without voltage constraint)	59.5 MVA
Combined 66kV feeders (with voltage constrained)	45.0 MVA

Ergon Energy has received connection enquiries from two major customers in the Emerald area. Connection of either one of these loads may exacerbate the voltage constraints such that additional network capability will be required before connection can be offered. Nonetheless, in order to clearly define our future demand scenarios, AECOM has assumed that neither of these customers will be connected.

Ergon Energy’s Draft Project Assessment Report forecasts that the 10% POE maximum demand will exceed the substation’s capacity constraint in FY2021. Connection of either new major loads would bring forward this date [6].

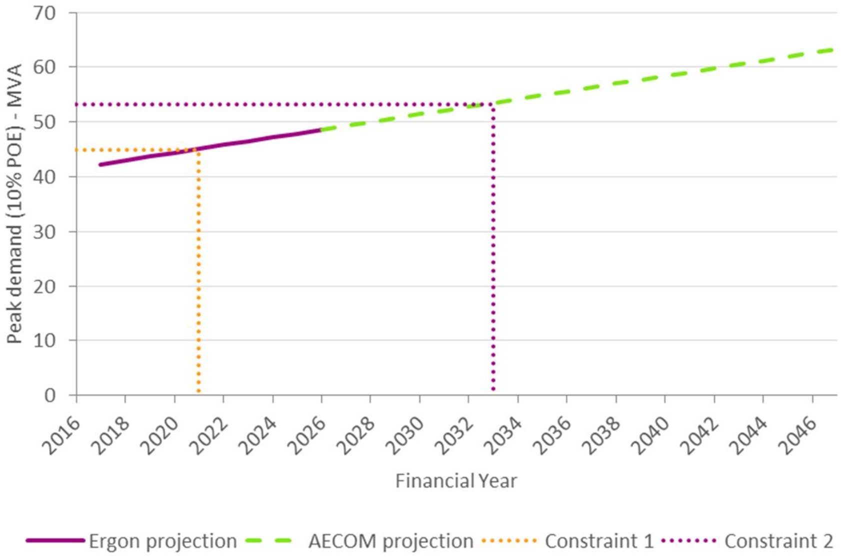
Ergon Energy has identified that its preferred network solution is to install 11MVAr of additional reactive compensation at Emerald ZS and also upgrade the Blackwater – Emerald Feeder by FY2020. Assuming neither major customer is connected, this will increase the N capability from 45 MVA to 53.2MVA under system normal conditions. The scope of this augmentation includes [6]:

- installing 3 x 3MVAr capacitor banks and a +/-2MVAr STATCOM at Emerald ZS, for a total of 11MVAr of reactive compensation in addition to the already existing 2 x 5MVAr capacitor banks
- upgrading the Blackwater–Emerald 66kV feeder to a maximum operational temperature of 100°C by pole rebutting.

3.3.4 Demand Forecast

Table 13 below shows Ergon Energy’s projection of maximum demand at Emerald ZS to 2020. Beyond 2020, AECOM has forecast peak demand to continue to grow at a rate of 0.7 MVA per year.

Table 13 Emerald ZS peak demand forecast (10% POE, no major new connections) [6]



3.3.5 Constraint 2 (2033)

Following implementation of Ergon Energy's preferred option, Emerald ZS's N capability increases from 45MVA to 52.3MVA. Steady growth in demand will lead to a new constraint when maximum demand grows above 53.2MVA in 2033. Given that the N capability of the upstream 66kV feeders is forecast to re-emerge as the constraint, there are limited network solutions. The most suitable solution (as discussed in Ergon Energy's 2016 RIT-D Draft Project Assessment Report) is to construct a new 66kV feeder from Blackwater to Emerald at a cost of $39.5 million plus an annual operating cost of 0.5% of the capital cost. This augmentation includes:

- construction of new 66kV feeder bays at Blackwater and Emerald substations
- construction of a new Single Circuit Concrete Pole (SCCP) 66kV feeder from Blackwater to Emerald, strung with Oxygen type conductor.

The additional capacity provided by the new 66kV feeder would make the transformers at Emerald ZS the new constraining plant, with an N Capability of 67.8MVA (cyclic operational rating in summer).

3.3.6 Constraint 2 – Investment Decision Details

AECOM's approach to modelling investment decisions is outlined in Section 4.3. It focuses on the use of an investment trigger when the modelled peak demand exceeds the substation capability. In this case study, it is clear that Ergon Energy does not require N-1 redundancy at the substation. As such, substation constraints are considered in N conditions.

AECOM has assumed that the new 66kV feeder will be selected as the preferred solution to Constraint 2. The timing of the investment decision has been estimated based on when the maximum demand (10% POE) is forecast to exceed the new dynamic rating (N capability of 53.2MVA). This augmentation trigger is a simplification of Ergon Energy's planning process (e.g. no consideration for Service Safety Net Targets) that aligns well with Ergon Energy's forecast investment timeframe for Constraint 1 where the intersection of 10% POE peak demand with the 45MVA load constraint occurs in FY2021. Ergon Energy is planning to implement its solution no later than 2020. This result indicates that the method is a reasonably accurate approximation for the purposes of this study.

Table 14 Summary of augmentation decision and cost

Item	Description	Comment
Constraint 1		
Initial substation constraint	45.0MVA	- Voltage constraint limiting feeder capacity
Augmentation description	Reactive compensation at the substation	- 3 x 3MVAr capacitor banks and a +/-2MVAr STATCOM

Item	Description	Comment
Augmentation cost	CAPEX: $6.5 million OPEX: 0.5% of CAPEX [6]	- CAPEX is spread over the 3 years preceding the constraint (25%, 50%, 25%)
Investment trigger	When forecast peak demand exceeds constraint (i.e. 45.0MVA)	Peak demand is forecast under 10% POE as per Ergon Energy's RIT-D Draft Project Assessment Report
New substation constraint	53.2MVA	Capacity is still constrained by the upstream 66kV feeders
Constraint 2		
Initial substation constraint	53.2MVA	Capacity is still constrained by the upstream 66kV feeders
Augmentation description	New 66kV upstream feeder	- New Single Circuit Concrete Pole (SCCP) 66kV feeder from Blackwater to Emerald - New 66kV feeder bays at Blackwater and Emerald substations
Augmentation cost	CAPEX: $39.5 million OPEX: 0.5% of CAPEX	- CAPEX is spread over the 3 years preceding the constraint (25%, 50%, 25%)
Investment trigger	When forecast peak demand exceeds constraint (i.e. 53.2 MVA)	Peak demand is forecast under 10% POE as per Ergon Energy's RIT-D Draft Project Assessment Report
New substation constraint	Summer: 67.8 MVA Winter: 75.6 MVA	- Once the upstream supply constraint is addressed (i.e. feeder capacity), the zone substation's transformers will become the new constraint - Emerald ZS's transformers have a combined Cyclic Operating Rating (COR) of 67.8MVA in summer and 75.6 MVA in winter

With the new substation capability exceeding projected demand, no further constraints are forecast within this study's 30 year timeframe.

3.4 Load Analysis

This section provides a high level overview of the peak demand patterns observed at the three case study substations. The analysis below provides an overview of the 3 years of 30-minute load data for each case study. Coincidently, each of the case studies experienced their highest peak at 5pm during summer months. In fact, all of the top 50 peak demand periods measured over the 3 years of data occurred during summer months.

Table 15 Summary of peak demand events at each case study

Case Study	Peak Demand Time (Last 3 Years)	Time Range of Top 50 Demand Events
Belconnen ZS	5pm 3 February 2014	1:30pm to 6:00pm
Flemington ZS	5pm 28 January 2014	10:30am to 8:30pm
Emerald ZS	5pm 18 November 2014	3:00pm to 8:00pm

This analysis indicates that many of the peak demand events occur during daylight hours, although many occur during periods of low solar generation. This pattern is demonstrated in Figure 6, Figure 7 and Figure 8. These histograms show the time of top 50 demand periods across the three years of raw load data. For Belconnen and Emerald substations, the peak demand events all occur within a 5 hour window, whereas at Flemington, the peaks are more spread across the day. At Belconnen ZS, solar PV shows good correlation with the peak demand periods, however for the other case studies it is clear that solar PV cannot directly address some of the peak demand periods that happen later in the evening. It is also worth noting that the absence of daylight savings in

Queensland plays a role by effectively making the solar generation profile end an hour earlier relative to the other case studies.

Figure 6 Histogram of top 50 peak demand periods with average solar output – Belconnen ZS

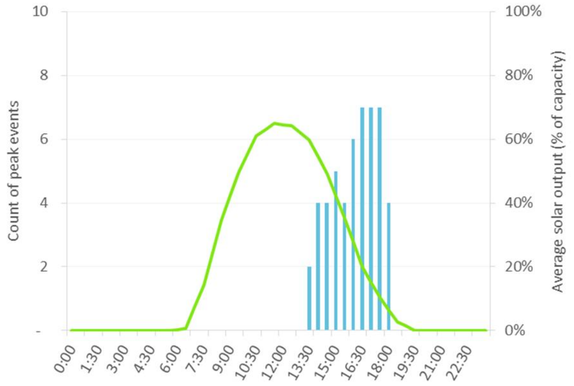


Figure 7 Histogram of top 50 peak demand periods with average solar output – Flemington ZS

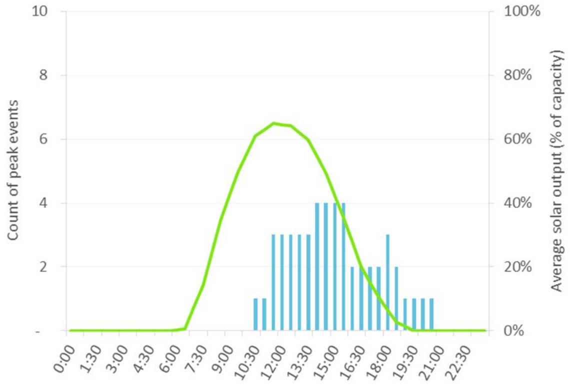
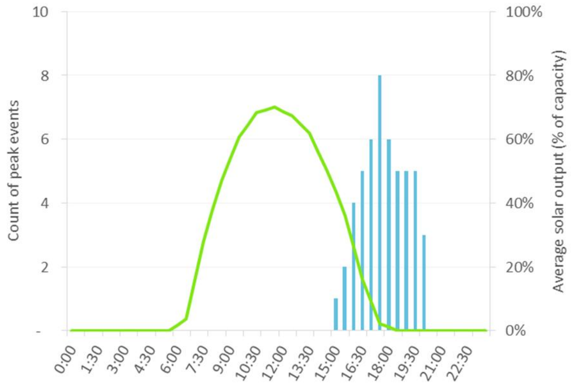


Figure 8 Histogram of top 50 peak demand periods with average solar output – Emerald ZS



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4.0 MODELLING APPROACH

4.0 Modelling Approach

AECOM has developed a model which analyses the impact of solar PV on peak demand at each of the three selected zone substations. This chapter describes AECOM's modelling approach as well as the key inputs and assumptions.

AECOM's modelling is comprised of two modules:

1. **Module 1: Demand Profile Model (DPM)**, which analyses existing and future demand profiles and solar profiles to determine the magnitude and timing of future peak demand events.
2. **Module 2: Financial Model**, which considers capital costs and operating costs required for network augmentation, and weighs up the costs of paying LGNCs against any benefits incurred through deferral of network augmentation.

4.1 Demand Profile Modelling

The technical model's function is to overlay future solar generation profiles on top of each substation's load profile. This aims to determine both the evolution of demand profiles due to solar PV installed under the Baseline scenario, as well as the impact of additional solar that is installed due to the LGNC payment. The model measures the coincidence with peak demand and its magnitude of impact. This process involves a number of steps, including:

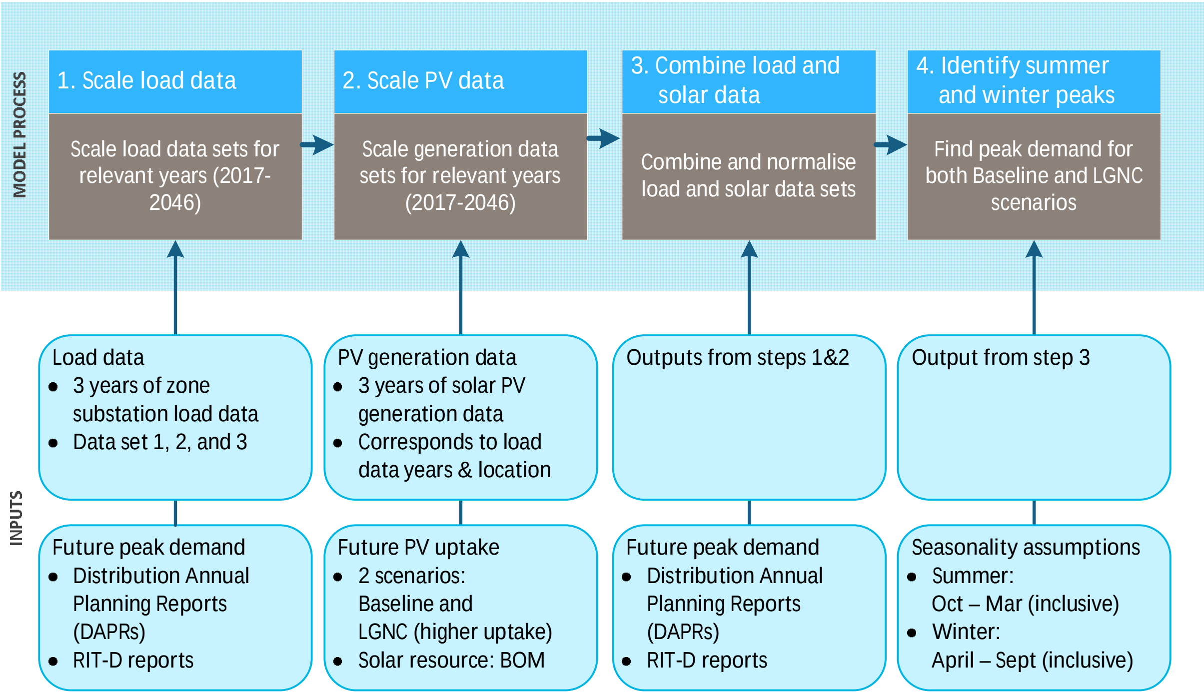
1. Obtain the historical load profile information for each substation (3 most recent years)
2. Obtain the corresponding historic solar generation profile for each substation using historical irradiation data (BOM satellite data)
3. Scale load profile to match forecast peak demand value
4. Determine additional solar uptake driven by LGNC
5. Combine the additional (i.e. caused by LGNC) solar generation profile to determine the resultant reduction in maximum demand.

This methodology allows direct comparison of peak demand between two scenarios which are differentiated by their treatment of future solar uptake. These include:

- **Baseline scenario**: future solar uptake is projected in line with AEMO's solar uptake forecasts as published in the 2016 National Electricity Forecasting Report
- **LGNC scenario:** the presence of an LGNC incentive leads to higher uptake of solar PV than is observed in the Baseline scenario.

This process is further described in Figure 9 below.

Figure 9 Overview of AECOM's technical model



The DPM model produces a 30 minute demand profile for each year of the study period under both scenarios (Baseline and LGNC scenarios). The key output of this model is peak demand in each year for both scenarios, where LGNCs are used to incentivise additional investment in solar. These outputs can then be placed into the financial model where the projected peak demand values are used to determine investment triggers in substation augmentation.

4.1.1 Inputs

An overview of the inputs used in AECOM's DPM is provided in Table 16 below.

Table 16 Summary of inputs into AECOM's technical model

Inputs	Belconnen	Flemington	Emerald
Load			
Load profile	For each case study, AECOM took 30 minute substation load data (supplied by the respective DNSP) for financial years 2012-13, 2013-14 and 2014-15. The use of multiple years broadens the dataset and (to some extent) mitigates against natural variations in demand.		
Peak demand growth rate	As per 3.1.4	As per 3.2.4	As per 3.3.4
Projection methodology	**<u>Baseline scenario</u>** Starting with the three years of 30 minute load profiles (i.e. "net demand"), AECOM removed existing solar generation[1] to determine the "gross demand". For each future year, the gross demand was scaled up to match the peak demand forecast by the DNSP. The solar load profile (scaled for future solar PV uptake) was then re-combined with the gross demand profile to provide a new "net demand" profile. In the event that the re-introduction of solar reduced the peak demand, AECOM performed an additional normalisation to re-scale the net demand profile to match the DNSP's original maximum demand projections.		

[1] Existing solar generation profiles were modelled by AECOM using historical BOM irradiation data. See "Irradiation data" and "Existing solar PV" input items below

Inputs	Belconnen	Flemington	Emerald
	LGNC scenario In the LGNC scenario, additional solar uptake is forecast relative to the Baseline. AECOM has taken the demand profile from the Baseline scenario and combined it with the additional solar uptake that occurs in the LGNC scenario to develop the demand profile for the LGNC scenario. More detail is provided in Sections 4.1.2 and 4.1.3.		
Solar			
Irradiation data	For each site, AECOM used 3 years of historic solar irradiation data (Source: Bureau of Meteorology) to produce solar generation profiles at each location. The 3 year historic irradiation data is co-incident with the historic load experienced at each location and hence reflects the relationship between weather, load and solar generation. AECOM used this data to produce solar generation profiles at each site using PVsyst software. AECOM re-calibrated its modelled solar generation to better reflect the under-performance of many household systems due to tilt, shading, soiling and azimuth. This is further discussed in Appendix A.		
Existing solar PV[2]	4.1 MW [4]	2.5 MW	6.6 MW
Future solar PV	**Baseline scenario** State-based uptake is available in AEMO's 2016 National Electricity Forecasting Report. For the Baseline scenario, AECOM took these uptake rates and scaled them down to the substation region based on the total number of customers served by that substation (relative to the entire state). **LGNC scenario** The presence of a LGNC leads to additional uptake of solar PV. See Section 4.1.4 for detail on the rate of additional uptake.		
LGNC starting price	LGNCs are proposed to be paid to solar PV customers based on the amount of export during peak tariff periods and the long run marginal cost of augmentation in each network. In its report for the AEMC, Marsden Jacob Associates (MJA) has recommended LGNC pricing structures for each DNSP. In addition, for various technologies, they have converted the pricing structure into an estimated annual LGNC revenue based on kilowatts installed capacity. These annual revenues for residential and commercial PV systems have been used by AECOM as per below (Table 9 of MJA report *Modelling the Value of Local Generation Network Credits,* 2 June 2016): DNSP / Solar PV - Residential / Solar PV - commercial ActewAGL / $8.65/kW / $3.82/kW Jemena / $9.91/kW / $1.29/kW Ergon West / $45.39/kW / $29.04/kW AECOM has used these values in our analysis without completing any verification.		
LGNC price over time	The AEMC has requested that the LGNC price should grow as the forecast augmentation date approaches as per the below assumptions: - Starting value as above		

DNSP	Solar PV - Residential	Solar PV - commercial
ActewAGL	$8.65/kW	$3.82/kW
Jemena	$9.91/kW	$1.29/kW
Ergon West	$45.39/kW	$29.04/kW

[2] AECOM has estimated existing solar PV at Emerald and Flemington by combining the ratio of capacity installed per dwelling (form APVI for the relevant postcode) with the number of residential customers serviced by each substation. It was assumed that 80% of electricity customers serviced by each substation were residential. For Belconnen, ActewAGL provided the solar PV capacity installed at Belconnen ZS in its Annual Planning Report.

Inputs	Belconnen	Flemington	Emerald
	- As the need for augmentation approaches, the value of LGNC increases linearly up to a maximum of twice the starting value - Once augmentation has taken place (or the constraint has been resolved), the value of LGNCs immediately falls to zero, from where it gradually increases over time.		

4.1.2 Demand forecasts

To forecast future demand profiles, AECOM has differentiated between “gross load” and “net load”, such that:

- **Gross load** is the total end user load
- **Net load** is the total end user load, minus generation from solar PV.

This separation is necessary because the load growth rate is far slower than the solar PV rate of growth (as projected in the Baseline scenario). Hence, scaling the net load alone would not capture the load profile impact of solar PV.

Instead, the modelling has scaled the gross load profile to the target level of maximum demand (as forecast by each DNSP), assuming that existing demand patterns continue into the future. The corresponding solar generation profiles were also scaled to match the forecast uptake of solar PV before the two profiles were combined into the net load profile. In the event that the re-introduction of solar PV reduced the peak demand, AECOM performed an additional normalisation to re-scale the net load profile to match the DNSP’s original maximum demand projections.

An example of the differentiation between gross load and peak load is provided in Figure 10 below. In this example, it is clear that solar reduces peak demand from 44.5MVA (gross load peak) to 41MVA (net load peak), as well as shifting the peak period to 7:30pm when there is no longer any solar generation.

Figure 10 Differentiation of gross load and peak load (example from Flemington ZS, 7 January 2025, data set 3)

AECOM has used growth rates as proposed by each DNSP in recent planning or RIT-D reports. The peak demand forecasts for each site are described in Sections 3.1.4, 3.2.4, and 3.3.4.

4.1.3 Solar uptake forecast

AEMO's state-based solar PV uptake projections were used to generate the forecast solar uptake rates for each site in the Baseline scenario. AEMO uptake forecasts are shown in Figure 11 and Table 17 below.

Figure 11 Historic and projected rooftop solar PV uptake across the NEM [2] [3]

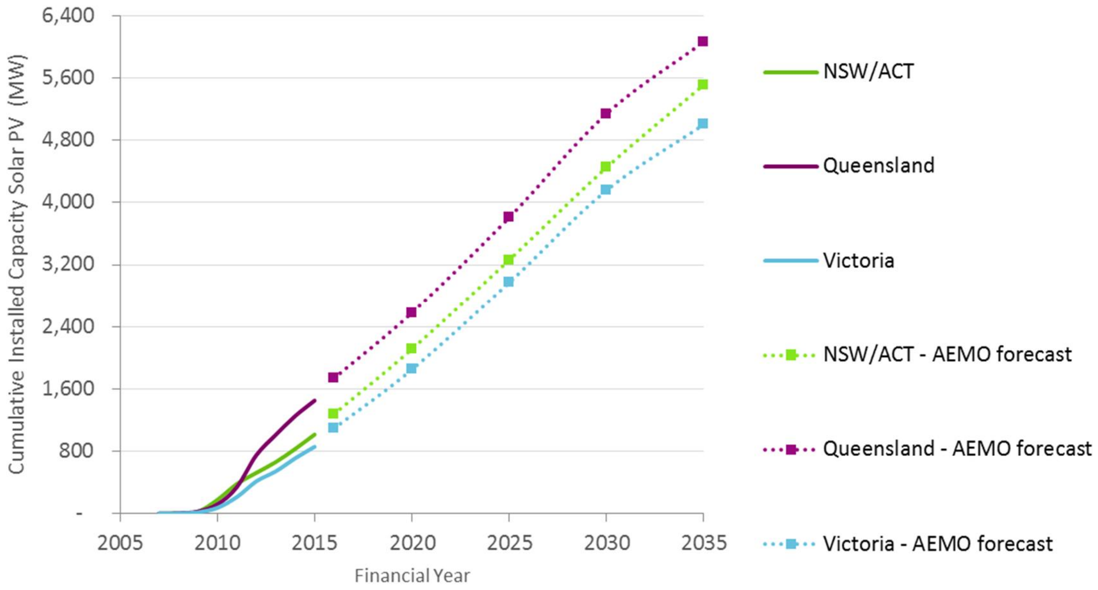


Table 17 AEMO solar PV forecast uptake [2]

	NSW/ACT	QLD	SA	TAS	VIC	NEM
FY17	1,278	1,737	718	113	1094	**4,939**
FY21	2,112	2,580	1,024	188	1,850	**7,754**
FY26	3,262	3,807	1,467	302	2,970	**11,807**
FY31	4,452	5,141	1,787	428	4,157	**15,965**
FY36	5,513	6,066	1,942	526	5,004	**19,049**

State-specific uptake projections were converted to installed capacity per customer, such that solar uptake projections could be made for each of the three zone substations. This equates to roughly an annual installation rate of 11kW per 100 customers in Queensland, 6kW per 100 customers in NSW/ACT and 8 kW per 100 customers in Victoria. These uptake rates were applied to each case study, with the resultant levels of solar PV shown in Table 18 for each site's forecast augmentation year.

Table 18 Forecast installed solar PV capacity in targeted site constraint years [2] [12] [13]

Site	No. Residential Customers	Site Uptake Rate	Current Installed Capacity	FY20 Capacity	FY23 Capacity	FY33 Capacity
	-	(MW/yr)	(MW)	(MW)	(MW)	(MW
Belconnen	11,000	0.70	4.01	6.82		
Flemington	15,000	1.18	1.19		9.43	
Emerald	8,700	1.00	5.25			22.17

It is noted that AECOM has assumed that the customer base supplied by the zone substation in each case study is able to maintain the AEMO uptake rates. AECOM has not accounted for any potential limitations such as saturation of suitable installations.

4.1.4 Incremental Impact of LGNCs on Solar PV Uptake Rates

In the Baseline scenario, the rate of solar PV uptake is well defined by the forecasts published in AEMO's 2016 National Electricity Forecasting Report (NEFR). However, for the LGNC scenario, it is important to capture the additional solar PV that would be installed due to the existence of a LGNC.

To estimate the additional solar that is installed, AECOM has considered the historical relationship between the simple payback of solar PV and the corresponding level of uptake. Reviewing solar uptake over the last 5 years, AECOM has derived a rough empirical relationship which can be used to estimate how much additional solar PV might be installed for any given LGNC revenue.

The correlation is based on the below relationship for simple payback, where the Annual Export Revenue is the value of exported solar PV, and Annual Self-Consumption Revenue is the value of avoided consumption charges from electricity used behind the meter.

$$Simple\ Payback = \frac{Capital\ Cost}{Annual\ Revenue} = \frac{Capital\ Cost}{Annual\ Export\ Revenue + Annual\ Self\ Consumption\ Revenue}$$

When collating the historical data, AECOM used the following inputs:

Table 19 Inputs used to derive empirical relationship between payback and solar PV uptake

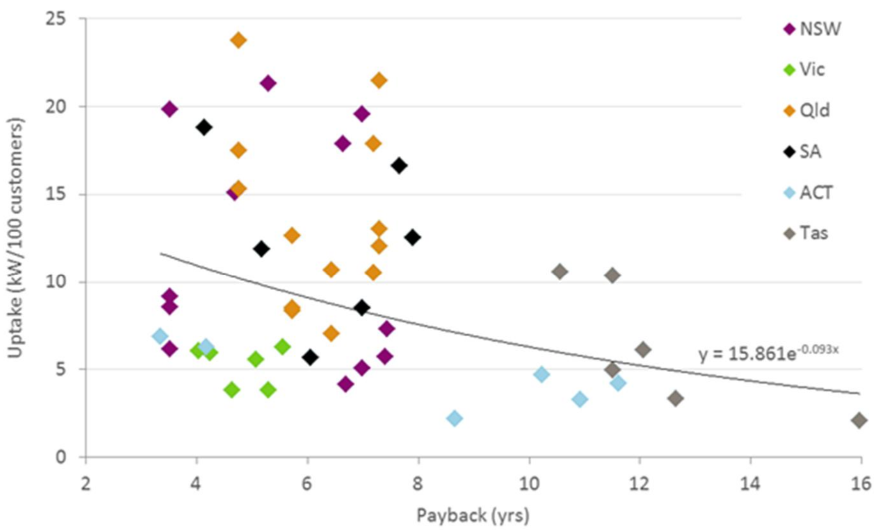
Item	Input
CAPEX	
CAPEX (after STC rebate)	Historic values as per Solar Choice website. Values vary per state and for each year. AECOM has used prices for 4kW systems as per January in each year. [14]
Annual revenue	
Export value	- Historic feed-in tariff programs for each state - Gross vs. net metering options - Where no feed-in tariff is applicable, export values have been estimated based on mandatory minimum solar export rates for each state, determined by: · Essential Services Commission of South Australia [15] · Queensland Competition Authority [16] · Victoria: Essential Services Commission · New South Wales: Independent Pricing and Regulatory Tribunal [17] · Tasmania: Office of the Tasmanian Economic Regulator [18] · Australian Capital Territory: Department of Energy and Planning [19]
Self-consumption value	- Based on historic electricity prices - Flat prices assumed - Major source: AER State of the Energy Market 2015 report [20] - Other sources: · AEMC retail competition reviews [21] · Queensland Competition Authority [22] · AGL retail tariffs [23] · Ergon Energy retail tariffs [24]
Generation volume	Total generation volumes as per Clean Energy Council's Consumer Guide (based on capital city in each state). [25]
Export / self-consume ratio	AECOM has estimated that 58% of generation is exported when gross metering is not in place based on analysis of the Ausgrid 300 homes data.

Other	
Uptake rates (installations per year)	- State based data from the Clean Energy Regulator [26] - DNSP-specific uptake, including: · Queensland – Ergon Energy [27] · Queensland – Energex [28] · New South Wales – Endeavour Energy [29]
Outliers	Some outliers were removed after it was clear that high uptakes were being observed in the year following the closure of a feed-in tariff, despite unappealing paybacks. It is possible that some customers ordered systems during feed-in tariff periods but encountered substantial delays to installation.

This analysis calculated that simple payback periods varied between 3 and 16 years, with generous feed in tariffs driving attractive business cases and high uptake in Queensland, South Australia and New South Wales. Interestingly, despite generous feed-in tariffs and attractive business cases, the Australian Capital Territory and Victoria did not experience the same high levels of uptake.

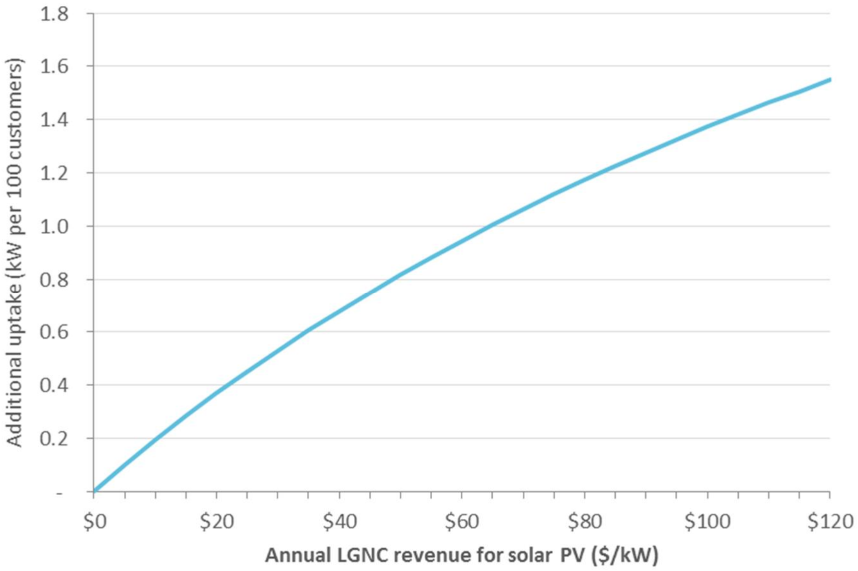
AECOM has plotted the above results onto a scatter chart to determine the relationship between simple payback and solar PV uptake. This is shown in Figure 12 below.

Figure 12 Empirical relationship between business case for solar PV and uptake



The relationship between payback and uptake can be converted into a relationship between LGNC revenue and additional uptake, as shown in Figure 13.

Figure 13 Additional annual uptake of solar PV (kW) for various LGNC revenues



As an example, in Emerald (8,700 customers) a LGNC revenue of $60/kW results in 0.94kW per year additional solar PV per 100 customers. Over 15 years this equates to 1.2MW additional solar capacity.

A number of observations can be made based on this analysis:

- While it is clear that the correlation is very poor, it is clear that a high level pattern emerges. This provides the study with a starting point from which further sensitivities can be devised.
- Low additional uptake is caused by the LGNC:
  - Historically, uptake of solar PV is not highly sensitive to the payback
  - The proposed LGNC revenue appears to have only a small impact on the business case. For example, LGNCs (depending on the site and export profile) may only add $50 to $150 of additional value per year to the solar system, which already generates annual value in the order of $800 per year
- There are significant limitations in developing the data for use in the scatter graph. A number of inputs have a large potential for significant variation in calculating the payback. These include:
  - System costs vary significant depending on the installer and the specific needs of the installation
  - The business case varies significantly depending on tariff structures, while our analysis only considers flat pricing
  - Solar export ratios vary significantly depending on the household
  - Long delays may be experienced between customer's decision to invest in solar and the installation date
  - During early years of feed-in tariffs, industry limitations restricted limited uptake rates due to connection speed and availability of installers
  - For many (particularly early adopters) solar PV investment was not a purely economic decision
  - In the above relationships, AECOM has not accounted for the impact of annual variations in LGNC revenue on payback. Similarly, customers will not have perfect foresight of LGNC revenue, which change on an annual basis. This revenue uncertainty will be difficult for customers trying to make investment decisions.
  - The analysis does not consider saturation points or government policy changes.

For the above "Empirical method", the rate of solar uptake increases by 2 to 14% (depending on the site and LGNC value). Given the poor correlation and the high uncertainty associated with the results, AECOM has included three additional sensitivities in its analysis, with higher uptake of solar PV. These sensitivities include

10%, 20% and 30% increases in the rate of uptake (relative to the Baseline scenario). Some of the advantages and disadvantages of the two methods are summarised in Table 20 below.

Table 20 Summary of pros and cons for each uptake modelling option

	Advantages	Disadvantages
Empirical uptake (LGNC scenario)	- Real world link between LGNC revenue and uptake based on data - Defensible methodology	- Very poor correlation in empirical dataset - Complex methodology with many assumptions
Percentage uptake (LGNC sensitivity scenarios)	- Simple to understand - Easy to customise methodology to desired results (i.e. set extreme scenarios)	- Highly arbitrary in nature

4.1.5 LGNC Pricing

The AEMC has specified that the LGNC should be applied in a dynamic fashion with the LGNC value gradually increasing to twice its initial amount as the need for augmentation approaches. Once augmentation has taken place (or the constraint has been resolved), the value of LGNC immediately falls to zero, from where it gradually increases over time

LGNCs are proposed to be paid to solar PV customers based on the amount of export during peak tariff periods and the long run marginal cost of augmentation in each network. In its report for the AEMC, Marsden Jacob Associates (MJA) has estimated annual LGNC revenues for residential and commercial PV systems as per below (Table 9 of MJA report *Modelling the Value of Local Generation Network Credits,* 2 June 2016):

Table 21 Estimated annual revenue from LGNCs for solar PV systems [1]

DNSP	Solar PV - Residential	Solar PV - Commercial
ActewAGL	$8.65/kW	$3.82/kW
Jemena	$9.91/kW	$1.29/kW
Ergon West	$45.39/kW	$29.04/kW

The values stated in Table 21 have been used as starting annual revenue values. The below figures (Figure 14, Figure 15 and Figure 16) demonstrate the expected method of application for these annual values. As shown in the figures, the LGNC annual value increases to double the original value at the forecast augmentation time, and then reduces to zero when the augmentation occurs. This application method was utilised in the modelling.

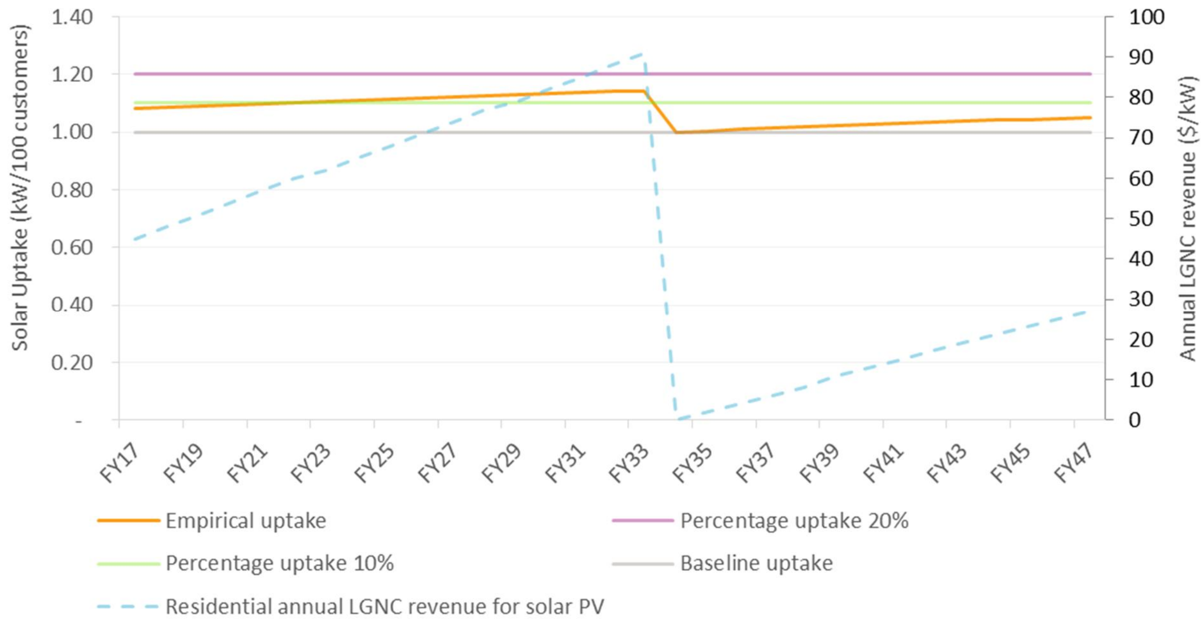
Figure 14 Belconnen LGNC annual revenue profile

Figure 15 Flemington LGNC annual revenue profile

Figure 16 Emerald LGNC annual revenue profile

Figure 17 shows that empirical uptake is initially below the 10% on Baseline level of uptake, then increases as the LGNC value increases until FY33 when the constraint is addressed and the value falls to zero. In FY33 when the LGNC value is zero, the empirical uptake is the same as the Baseline, since there is no extra uptake due to LGNCs at this time. After FY33, the value of LGNCs gradually increases towards a future constraint, and the solar PV uptake also increases gradually (following the LGNC value).

Figure 17 Emerald: relationship between solar uptake and LGNC revenue



4.2 Financial Model

The financial model takes the outputs from the Demand Profile Model (DPM) and combines it with the costs of network augmentation and payment of LGNCs to determine to whether there is a net cost or benefit from implementing LGNCs. The model directly compares the LGNC scenario (and its sensitivities) against the Baseline scenario to compare the respective Net Present Values. This involves a number of steps:

1. Determine investment years for each scenario by comparing maximum demand (output of DPM) against the constraints of each substation
2. Assign CAPEX and OPEX for each investment trigger
3. Determine NPV under each scenario.

4.2.1 Inputs

An overview of the inputs used in AECOM's financial model is provided in Table 22

Table 22 Summary of inputs into AECOM's technical model

	Belconnen (ACT)	Flemington (VIC)	Emerald (QLD)
Investment triggers			
Constraint 1	63 MVA	Not applicable as trigger has already occurred	45 MVA
Constraint 2	126 MVA	40.8 MVA	53.2 MVA
Constraint 3	N/A	75.6 MVA	67.8 MVA
CAPEX and OPEX			
CAPEX – Augmentation 1	$12.62 million (FY2019)	$4.8 million (FY2019)	$6.5 million (FY2021)
CAPEX – Augmentation 2	N/A	$10.3 million (FY2023)	$39.5 million (FY2033)
OPEX – Augmentation 1	0.1% of CAPEX	0.1% of CAPEX	0.1% of CAPEX
OPEX – Augmentation 2	N/A	0.1% of CAPEX	0.5% of CAPEX

Financial	
Model type	Real, pre-tax cash flow model
Discount rate (real)	6.5%

4.3 Network Planning

The planning process associated with the upgrade of network assets is complex, weighing up the cost of rectifying constraints against the risk and value of lost load. While network planning is trending away from deterministic approaches towards probabilistic approaches, strong elements of deterministic planning are still utilised within a probabilistic approach. Deterministic planning requires the network meet certain rules or standards and dictate investment to meet N, N-1 or N-2 contingency criteria. These redundancy levels determine the level of reliability and security to which a network is designed.

In this study, AECOM is not able to fully replicate the complex planning procedures undertaken by DNSPs to determine the design and timing of network augmentations. Nonetheless, AECOM has sought to approximate the process that determines timing of investment based on the growth of peak demand above substation capacity thresholds. For each of the three case studies, planning and RIT-D reports were reviewed to determine the most appropriate method for estimating the timing of investment decisions. The resultant methodologies are described in Table 23 below. To enable modelling of augmentation investment deferral, each methodology is based on a simple trigger. Investment is triggered when maximum demand projections exceed the substation constraint.

It is noted that definition of the triggers (redundancy and POE load forecast) has no material impact on the modelling results other than the timing of the investment in the Baseline scenario (as long as there is consistency in the investment decision methodology for the Baseline and LGNC scenarios). Given that the modelling of the LGNC scenario measures peak demand reduction, the results are largely independent of the redundancy requirement and POE inputs.

Table 23 Summary of investment decision methodologies

Case Study	Redundancy Requirement	POE Load Forecast Used[3]	Investment Decision and Rationale
Belconnen ZS	N-1	50% POE	The investment decision occurs such that the augmentation provides additional capacity to the substation before the 50% POE demand forecast exceeds the N-1 cyclic rating of the transformers (i.e. 63 MVA; the transformers are the constraining equipment). 50% POE was used because its intersection with the substation's capacity constraint was better aligned with ActewAGL's proposed timing of its proposed augmentation project. AECOM selected N-1 redundancy for determining the constraint capacity as ActewAGL had made it clear in its Annual Planning Report that N-1 was required.
Flemington ZS	N-1	50% POE	The investment decision occurs such that the augmentation provides additional capacity to the substation before the 50% POE demand forecast exceeds the N-1 capacity (i.e. 24 MVA for the first constraint, 40.8 MVA for the second constraint) AECOM has used 50% POE as an approximation of the investment trigger in the probabilistic planning process.

[3] Probability of Exceedence (POE) is defined by the AER as "*The 50% PoE demand level is the level of maximum demand that, on average would be exceeded in 50 per cent of seasons. It can be thought of as the maximum demand that would be observed or exceeded once every two years on average"* [2]
In this study, 10% PoE and 50% PoE are used to determine the year a network constraint occurs. The suitability of 10% PoE compared with 50% PoE is dependent on the individual site.

Case Study	Redundancy Requirement	POE Load Forecast Used[3]	Investment Decision and Rationale
			50% POE was used as Jemena's RIT-D Stage 1 report indicated that 50% POE demand conditions was used as a trigger for Jemena's internal risk mitigation analysis, when it exceeds 67% of the equipment's rating [5]. N-1 redundancy is a clear requirement as per Jemena's RIT-D Stage 1 report. As such, AECOM has used N-1 requirements when defining Flemington's constraint capacity.
Emerald ZS	N	10% POE	The investment decision occurs such that the augmentation is completed prior to the 10% POE demand forecast exceeding the transformers N rating (i.e. 45 MVA for the first constraint, 53.2 MVA for the second constraint) AECOM has used 10% POE as an approximation of the investment trigger in the probabilistic planning process. 10% POE was used because its intersection with the substation's first capacity constraint was better aligned with Ergon Energy's proposed timing of its proposed augmentation project. N-1 redundancy is not required by Ergon Energy at this substation (most likely due to its remote nature and the lower value of customer reliability relative to the additional cost). As such, AECOM has used N ratings when defining Emerald's constraint capacity.

Built to deliver a better world

5.0 RESULTS

5.0 Results

This chapter summarises modelling results, focusing on the impact of solar PV on peak demand events as well as the financial impact of any augmentation deferral that occurs.

The results focus on the impact of the LGNC scenario relative to the Baseline scenario. The LGNC scenario includes four sensitivities where the additional LGNC solar uptake is varied. These include:

1. Empirical uptake rate (see Section 4.1.4)
2. Solar PV uptake rate is 10% above Baseline uptake rate ("10% solar PV on Baseline")
3. Solar PV uptake rate is 20% above Baseline uptake rate ("20% solar PV on Baseline")
4. Solar PV uptake rate is 30% above Baseline uptake rate ("30% solar PV on Baseline").

For simplicity of interpreting the patterns, AECOM's graphical results focus on the 10% solar PV on Baseline sensitivity as it communicates high level trends better than the Empirical uptake scenario. Nonetheless, the results for all sensitivities are provided.

5.1 Belconnen

5.1.1 Peak Reduction

The modelling has shown that the impact of additional LGNC solar on peak demand at Belconnen ZS can vary significantly, depending on whether the peak occurs in the middle of a summer afternoon or a winter evening. Data Sets 1 and 2 show significant levels of peak reduction, whereas Data Set 3 does not because its peak period is not during sunlight hours. This is summarised in Table 24 where Data Sets 1 and 2 show peak reduction every year until 2032, when the peak demand period moves out of sunlight hours. The magnitude of the peak reduction is small with only 0.04-0.23MVA of peak reduction observed across the 4 sensitivity scenarios. The small magnitude is due to the peaks coinciding with periods of low solar irradiation (5:00pm to 6:00pm).

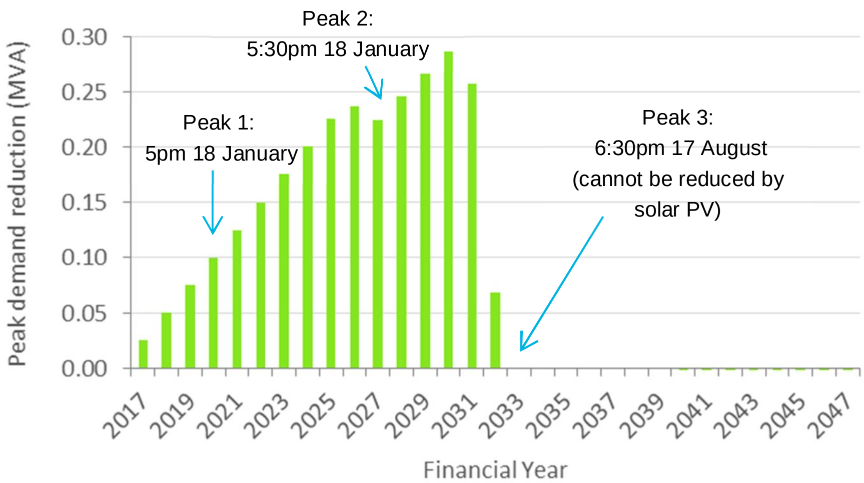
Table 24 Belconnen ZS peak reduction observed as a result of additional LGNC solar

	Data Set 1	Data Set 2	Data Set 3
Time of peak period (Baseline)[4]	5:00pm 18 January	5:30pm 3 February	6:30pm 30 June
Peak reduction observed	ü	ü	X
Final year of peak reduction observed	2032	2032	N/A
Peak Demand Reduction (in forecast augmentation year)	**Data Set 1**	**Data Set 2**	**Data Set 3**
Empirical uptake (effectively 4.1% - 7.9% uptake)	0.04 MVA	0.04 MVA	No reduction
10% PV uptake	0.08 MVA	0.06 MVA	No reduction
20% PV uptake	0.15 MVA	0.13 MVA	No reduction
30% PV uptake	0.23 MVA	0.19 MVA	No reduction

A key observation in the results is that over the course of time, the peak period shifts in the Baseline scenario. This is due to increasing amounts of solar in the Baseline scenario reducing the demand peak load. This reduction is so significant that, over time, a new peak emerges outside sunlight hours. Once the peak period has been shifted, there is no additional peak demand reduction that can be delivered from additional solar in the LGNC scenario. Figure 18 shows the peak demand reduction due to the introduction of LGNCs (solar uptake sensitivity: 10% solar PV on Baseline) for Data Set 1.

[4] The times given are the peak period in the Baseline for the year in which the augmentation is forecast to occur. It is noted that the peak period changes with time.

Figure 18 Belconnen peak demand reduction, 10% solar PV on Baseline, Data Set 1



The figure indicates that the magnitude of peak reduction increases each year from 2017 until 2027 as increasing amounts of additional LGNC solar are installed. Before 2027 the peak occurs at 5pm on 18 January (Figure 19); and in 2027 it shifts to 5:30pm on 18 January (Figure 20).

Additional LGNC solar continues to reduce Peak 2 until 2033, at which point the peak is reduced to the extent that it no longer occurs on 18 January. The new peak (Peak 3) occurs on 17 August at 6:30pm (Figure 21). This peak is not coincident with solar generation and therefore cannot be reduced through additional solar. Thus, from 2032 onwards, the peak reduction shown in Figure 18 is zero.

Figure 19 Belconnen, Data Set 1, 10% solar PV on Baseline 18 January 2026, Peak at 5pm

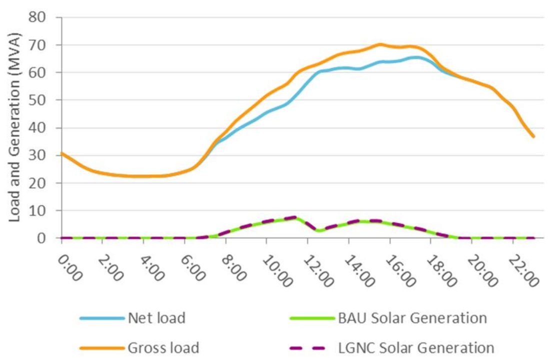


Figure 20 Belconnen, Data Set 1, 10% solar PV on Baseline 18 January 2032, Peak at 5:30pm

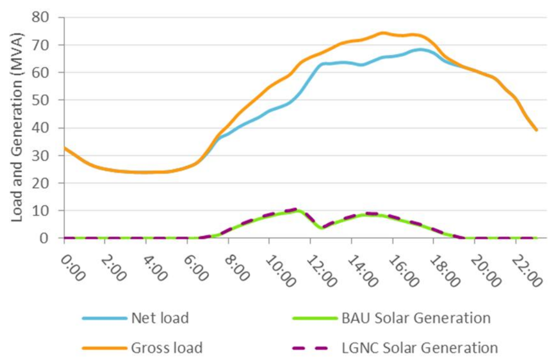
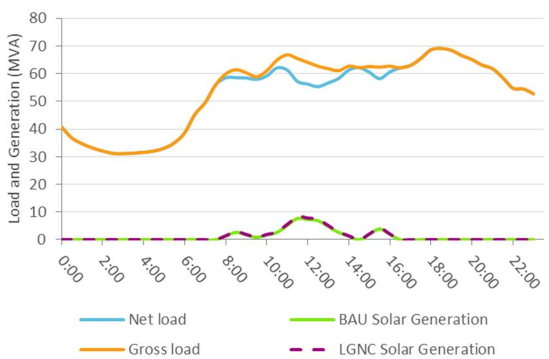
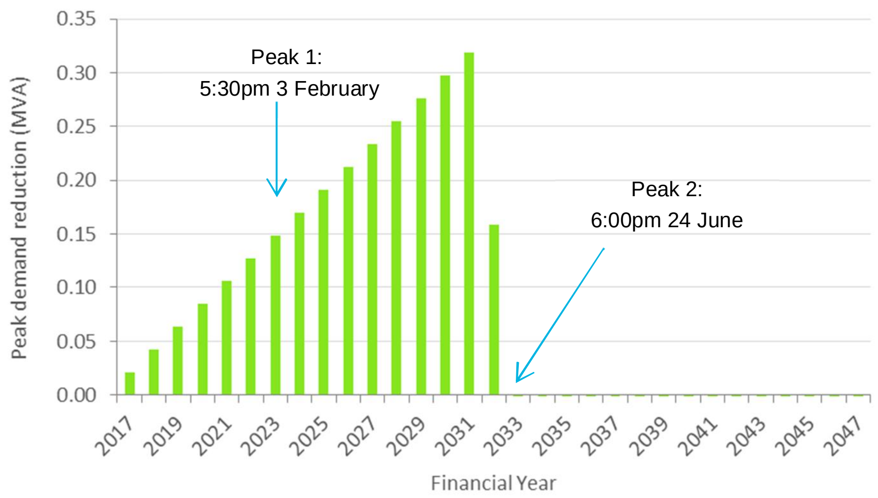


Figure 21 Belconnen, Data Set 1, 10% solar PV on Baseline 17 August 2033



Similarly, Data Set 2 shows that additional LGNC solar contributes to peak reduction until 2033 as shown in Figure 22. The initial peak occurs at 5:30pm on 3 February, and then in 2033 is shifted to 6pm on 24 June, at which point there is no solar generation available to reduce the peak demand.

Figure 22 Peak demand reduction, 10% solar PV on Baseline, Data Set 2



Data Set 3 shows no peak reduction at all, since the peak demand period (6:30pm 30 June) occurs outside of sunlight hours for that time of the year.

5.1.2 Augmentation Deferral

The observed reduction in peak demand caused by LGNCs does not appear large enough to defer augmentation at Belconnen ZS. This is because the reduction in peak demand is not large enough to take the maximum demand event below the 63MVA trigger. This result was common to all three data sets and uptake sensitivities, as shown in Table 25.

Table 25 Belconnen ZS deferral observed

	Data Set 1	Data Set 2	Data Set 3
Empirical uptake (effectively 4.1% - 7.9% uptake)	x	x	x
10% PV uptake	x	x	x
20% PV uptake	x	x	x
30% PV uptake	x	x	x
Peak time in augmentation trigger year	5:00pm 18 January FY19	5:30pm 3 February FY19	6:30pm 30 June FY19

5.1.3 Non-network Solution Requirements

In its 2015 Distribution Annual Planning Report, ActewAGL estimated that non-network proposals would be required to provide the following reductions in maximum demand to enable the deferral of the 3rd transformer augmentation.

Table 26 RIT-D peak demand reduction requirement [4]

Year	Required Reduction in Peak Demand
2020	2.5 MVA
2021	5 MVA
2022	7.5 MVA

Year	Required Reduction in Peak Demand
2023	10MVA

The modelling results indicate that the LGNC rule change could only incentivise a maximum of approximately 0.3MVA of peak demand reduction, well short of the requirement outlined above in Table 26.

5.1.4 Capacity Exceedance

The analysis presented in this Chapter assumes that the augmentation is triggered in the first year that demand exceeds the designated substation capacity constraint. For instance, in Belconnen the substation constraint is defined at N-1 capacity of 63MVA and the first year in which the modelled load profile exceeds 63MVA is FY19. Therefore, the investment trigger occurs in FY19.

This method was adopted as a simplification of the complex planning approach. However the approach is highly binary and does not take into account the probabilities of varying demand or the materiality of demand exceeding the constraint.

In this section, AECOM has quantified the “hours at risk” and the “energy at risk”, defining these terms as the length of time that the modelled load exceeds the designated substation capacity constraint, and the level of demand that is above that limit. If these metrics are low, the level of risk could be deemed acceptable and the investment trigger may be deferred.

Figure 23 shows the volume of energy at risk in the investment trigger year and for the three following years. This figure indicates the volume of energy at risk under both the Baseline scenario and the LGNC scenario. It shows that the total volume lost is very low in both scenarios (only 3.7MWh in the constraint year FY19), with the LGNC scenario offering marginally smaller energy at risk.

Similarly, Figure 24 shows that the number of hours at risk each year is small. Both scenarios result in only eight hours during which the demand exceeded the substation capacity in the investment trigger year (FY19) in the Baseline scenario. The LGNC scenario provided no reduction in this metric in any of the years shown with the exception of 2020.

Examining Figure 23 and Figure 24 shows that the LGNC scenario (sensitivity: 10% solar uptake) has minimal impact to the Baseline scenario in terms of reducing volume of energy at risk and the number of capacity exceedance events. The trend in 2021 and 2022 for a reduction in both metrics is due to reduced demand forecasts for these years as provided by ActewAGL (see Section 3.1.4).

Figure 23 **Belconnen energy at risk**
10% solar uptake, Data Set 1

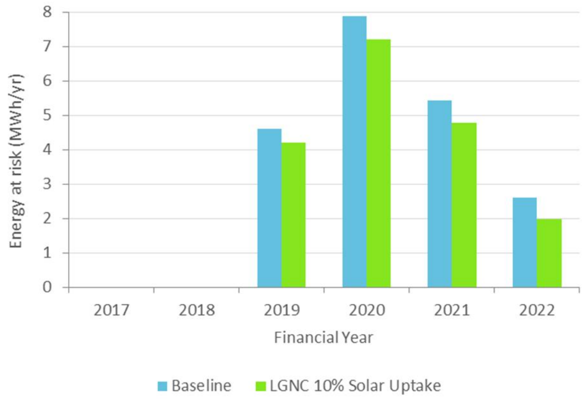


Figure 24 **Belconnen hours at risk**
10% solar uptake, Data Set 1

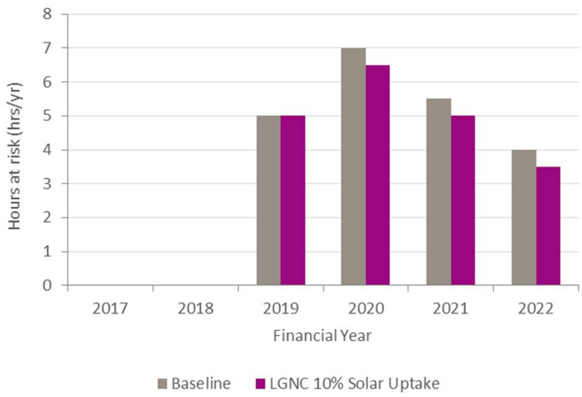


Figure 25, Figure 26 and Figure 27 provide a comparison of these two metrics under each LGNC sensitivity scenario. At a high level, two key messages can be extracted from examining these figures:

- Increased levels of solar PV can result in greater reductions to energy at risk. This is indicated clearly in Figure 25 and Figure 26

- There is no guarantee that solar PV will contribute to reducing the energy at risk. This is demonstrated in Data Set 3 (Figure 27) where additional solar has no impact on the peak demand. This is because the peak demand period in Data Set 3 occurs outside of sunlight hours (6:30pm 30 June).

Figure 25 Belconnen energy at risk, Data Set 1

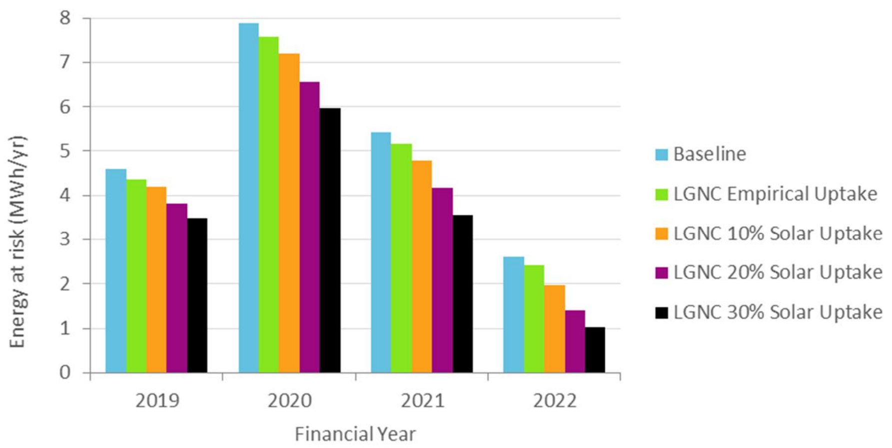


Figure 26 Belconnen energy at risk, Data Set 2

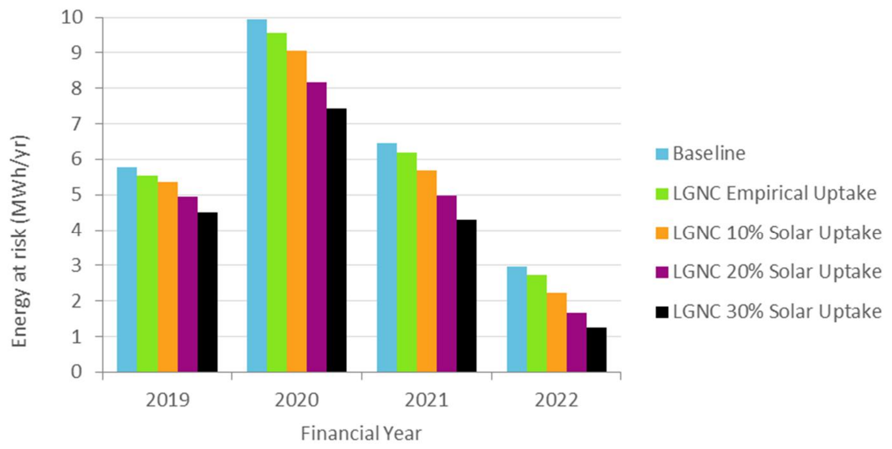
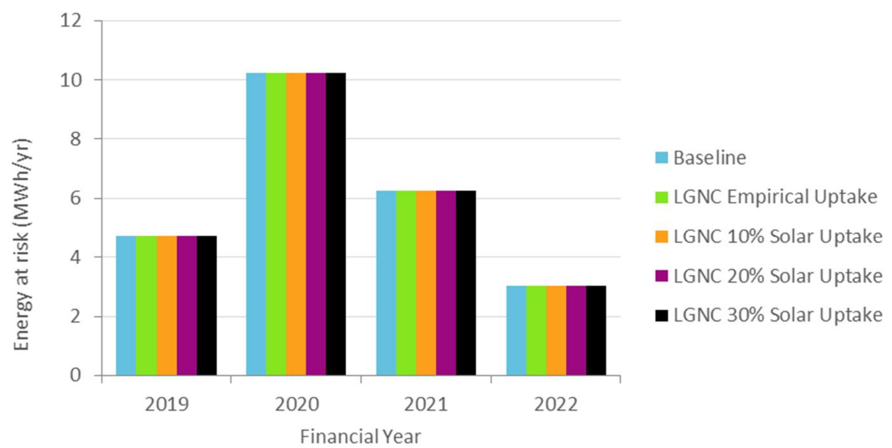


Figure 27 Belconnen energy at risk, Data Set 3



5.1.5 Reverse Power Flows

There is no reverse power flow observed at Belconnen ZS over the study period for any of the uptake sensitivity scenarios. It is noted that an imbalance in solar PV concentrations on individual feeders could result in reverse flows on feeders with high concentrations of PV.

5.2 Flemington

5.2.1 Peak Reduction

Only Data Sets 2 and 3 experienced peak reduction at Flemington ZS as a direct result of additional LGNC solar. This is summarised in Table 27 where Data Set 3 experiences peak reduction for up to 3 years, whereas Data Set 2 experiences peak reduction every year within the study period. As with Belconnen Zone Substation, the peak period at Flemington shifts over time due to increasing penetrations of solar in the Baseline scenario. Once the peak period has been shifted outside of sunlight hours, there is no additional peak demand reduction that can be delivered from additional solar in the LGNC scenario.

Table 27 Flemington peak reduction observed

	Data Set 1	Data Set 2	Data Set 3
Time of peak period (Baseline)[5]	7:30pm 18 November	7:00pm 28 January	6:30pm 7 January
Peak reduction observed	X	ü	ü
Final year of peak reduction observed	N/A	2047	2020
Peak Demand Reduction (in forecast augmentation year)	**Data Set 1**	**Data Set 2**	**Data Set 3**
Empirical uptake (effectively 1.8% - 3.6% uptake)	No reduction	0.01 MVA	No reduction
10% PV uptake	No reduction	0.07 MVA	No reduction
20% PV uptake	No reduction	0.14 MVA	No reduction
30% PV uptake	No reduction	0.20 MVA	No reduction

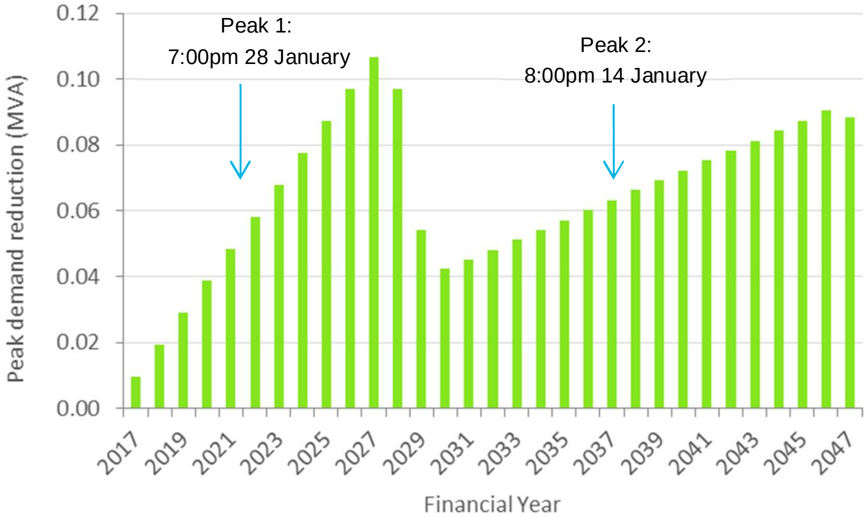
As noted, there was no peak reduction observed for Data Set 1. Figure 28 and Figure 31 show the peak demand reduction due to additional LGNC solar over the study period for Data Sets 2 and 3 respectively.

For Data Set 2, Figure 28 also shows that two separate peaks are addressed; 7:00pm 28 January and 8:00pm 14 January. Note that between 2028 and 2030 the Baseline scenario peak is at 7:00pm on 28 January, whilst the LGNC scenario's peak is at 8:00pm on 14 January. The peak reduction observed is therefore the difference between these two times and the impact decreases each year until the peak in the Baseline scenario also moves to 8:00pm on 14 January in 2030.

This Data Set shows peak reduction over the entire study period, however it is worth noting that the magnitude of peak reduction is low, in the order of 100kW. This value of reduction is negligible, particularly given the error inherent in demand forecasting.

[5] The times given are the peak period in the Baseline for the first year of analysis. It is noted that the peak period changes with time.

Figure 28 **Flemington peak demand reduction, 10% solar PV on Baseline, Data Set 2**



The diurnal profiles for each of the peak days in Data Set 2 are provided below.

Figure 29 **Flemington, Data Set 2, 10% solar PV on Baseline 28 January 2030**

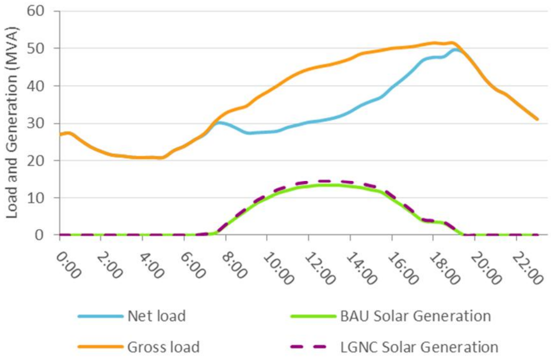


Figure 30 **Flemington, Data Set 2, 10% solar PV on Baseline 14 January 2047**

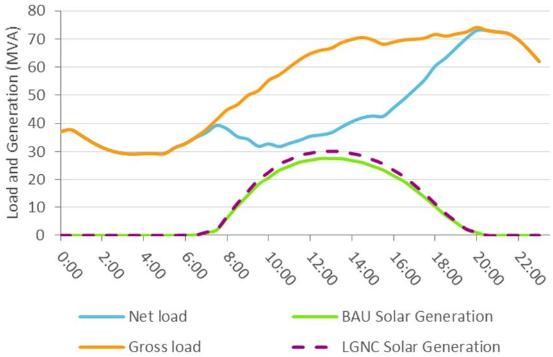
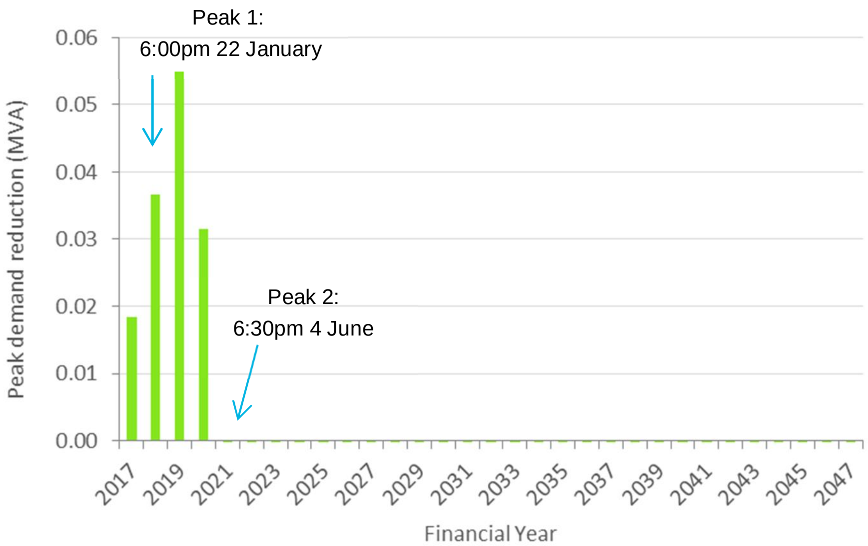


Figure 31 shows the peak demand reduction observed for Data Set 3. A 30kVA reduction occurs in FY20 when the Baseline peak occurs at 6:00pm on 22 January. In the following year, the peak moves to 6:30pm 4 June, when no solar generation is occurring.

Figure 31 Flemington peak demand reduction, 10% solar PV on Baseline, Data Set 3



5.2.2 Augmentation Deferral

At the Flemington ZS, the reduction in peak demand caused by LGNCs is not large enough to defer augmentation as shown in Table 28. This is because the reduction in peak demand is not large enough to take the maximum demand event below the 40.8MVA trigger. This result was common to all three data sets and uptake sensitivity scenarios.

Table 28 Flemington deferral observed

	Data Set 1	Data Set 2	Data Set 3
Empirical uptake (effectively 1.8% - 3.6% uptake)	x	x	x
10% PV uptake	x	x	x
20% PV uptake	x	x	x
30% PV uptake	x	x	x
Peak time in augmentation trigger year	7:30pm 18 February FY23	7:00pm 28 January FY23	6:30pm 4 June FY23

5.2.3 Capacity Exceedance

Capacity exceedance refers to the volume of load above the substation capacity in the years following the forecast augmentation trigger, if that augmentation did not occur. In the case of Flemington, the forecast augmentation trigger is scheduled to occur in FY23, so FY23 to FY26 are considered. Figure 32 shows the energy at risk in each year and Figure 33 shows the hours at risk. Both metrics increase steadily from FY23 onwards, with minimal reduction due to the additional solar under the LGNC 10% solar scenario.

Figure 32 Flemington energy at risk 10% solar uptake, Data Set 1

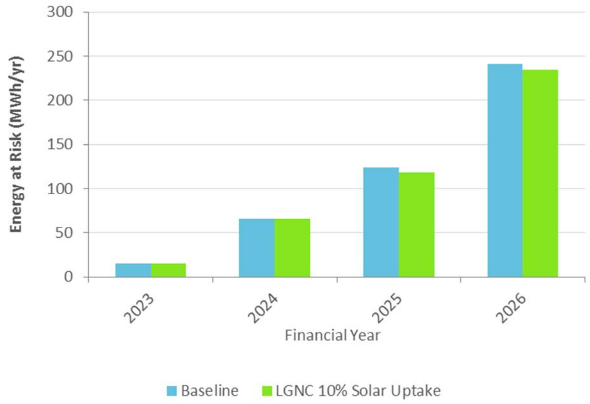


Figure 33 Flemington hours at risk 10% solar uptake, Data Set 1

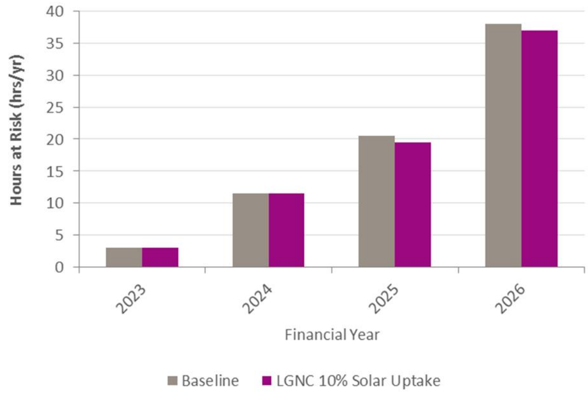


Figure 34, Figure 35 and Figure 36 provide a comparison of these two metrics under each LGNC sensitivity scenario. These figures reinforce the key learning in Section 5.1.4, that solar PV can reduce the volume of energy at risk and the hours at risk, however does not do so reliably.

Figure 34 Flemington energy at risk, Data Set 1

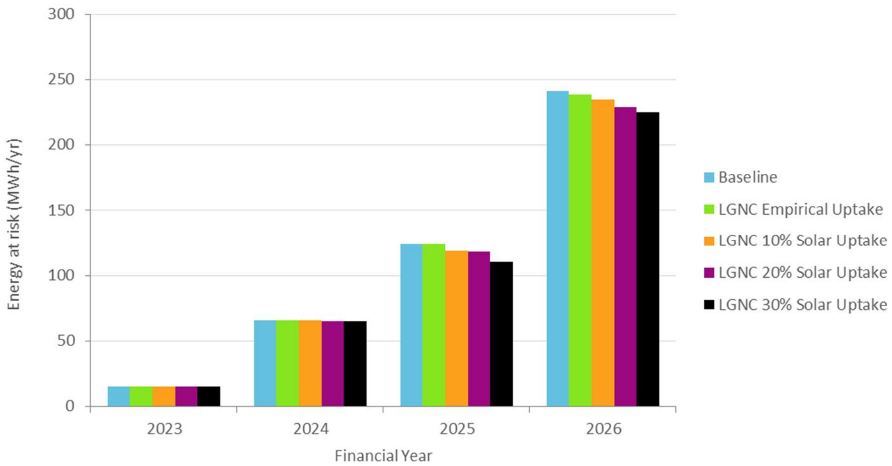


Figure 35 Flemington energy at risk, Data Set 2

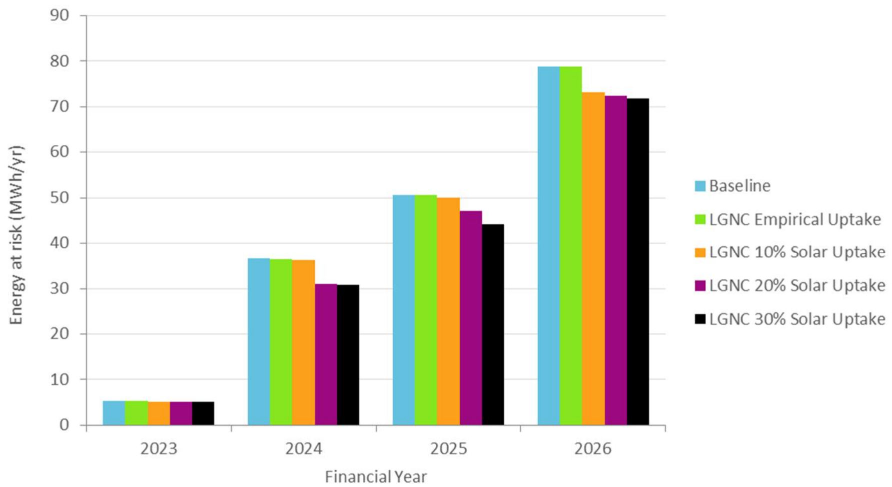
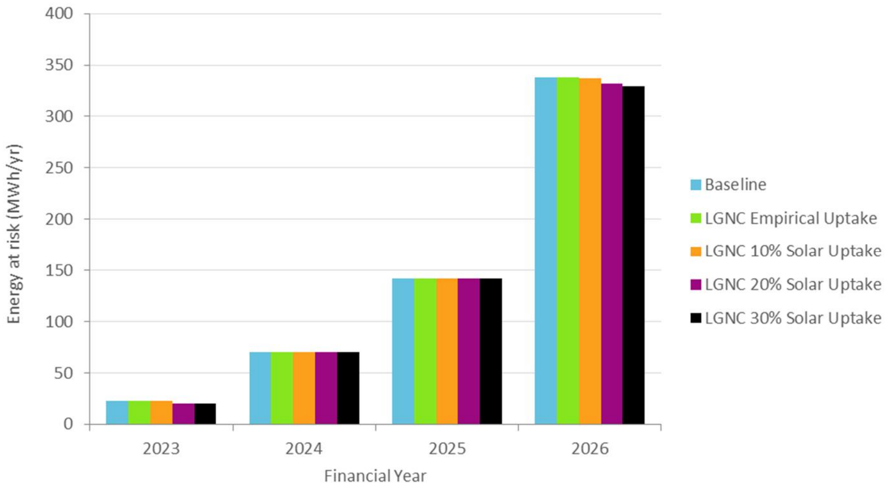


Figure 36 Flemington energy at risk, Data Set 3



5.2.4 Reverse Power Flows

There is no reverse flow observed at the substation under the Baseline scenario for all three Data Sets. With additional solar under the Empirical uptake scenario, there is only one reverse flow event under Data Set 2 and this does not occur until 2047. There are zero reverse flow events observed for all other Data Sets under the Empirical uptake scenario.

With 10%, 20% and 30% solar uptake on Baseline, there is reverse flow observed for all Data Sets, albeit minor reverse flows under Data Set 1 and 3. The most reverse flow is observed under Data Set 2, with the number of reverse flow events per year for this Data Set shown in Figure 37.

Figure 37 Flemington – Number of reverse flow events per year, Data Set 2

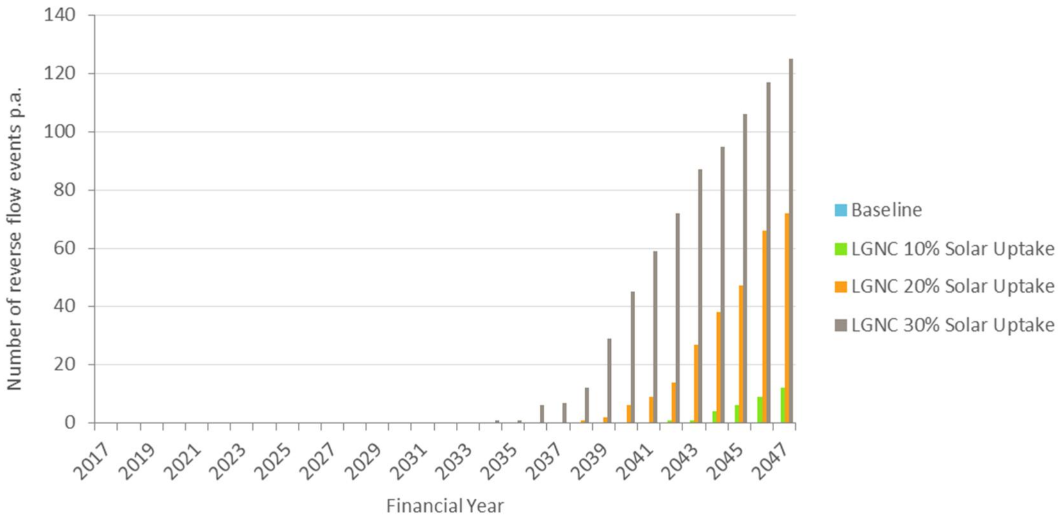


Figure 38 and Figure 39 show the peak reverse flow day for the 10% solar PV uptake scenario for Data Set 2. The figures show the daily profiles in the first year reverse flow occurs (2042) and in the final study year (2047) respectively. The potential impacts of reverse flow are discussed in detail in Section 7.0.

Note that the solar generation profiles in Figure 38 and Figure 39 do not exhibit a typical bell-curve solar profile shape. The peaks and troughs which are shown are due to the weather conditions (i.e. clouds) which occurred in the original Data Set 2 inputs.

Figure 38 **Flemington peak reverse flow day 4 January 2042 10% solar PV on Baseline, Data Set 2**

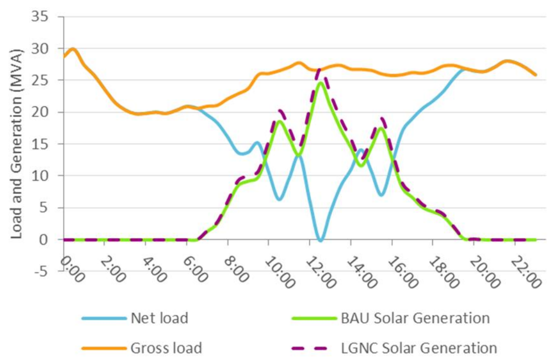
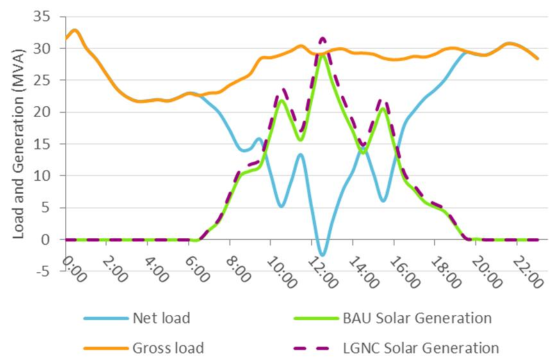


Figure 39 **Flemington peak reverse flow day 4 January 2047 10% solar PV on Baseline, Data Set 2**



5.3 Emerald

5.3.1 Peak Reduction

Two of the three data sets experienced peak reduction at Emerald ZS as a direct result of additional LGNC solar. This is summarised in Table 29 below, which shows peak reductions for Data Set 2 until 2021, and for Data Set 3 for the entirety of the study period. No peak reduction was observed under Data Set 1 for Emerald since the peak occurs outside sunshine hours.

As with Belconnen and Flemington zone substations, the peak period at Emerald shifts over time due to increasing penetrations of solar in the Baseline scenario. Once the peak period has been shifted outside of sunlight hours, there is no additional peak demand reduction that can be delivered from additional solar in the LGNC scenario.

Figure 40 and Figure 41 show the peak demand reduction due to additional LGNC solar over the study period for Data Sets 2 and 3 respectively.

Figure 40 **Emerald peak demand reduction, 10% solar PV on Baseline, Data Set 2**

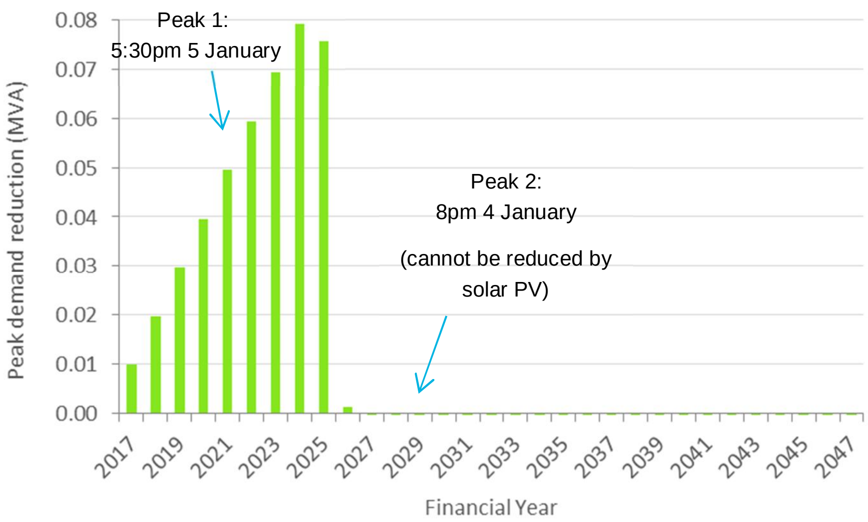


Figure 41 Emerald peak demand reduction, 10% solar PV on Baseline, Data Set 3

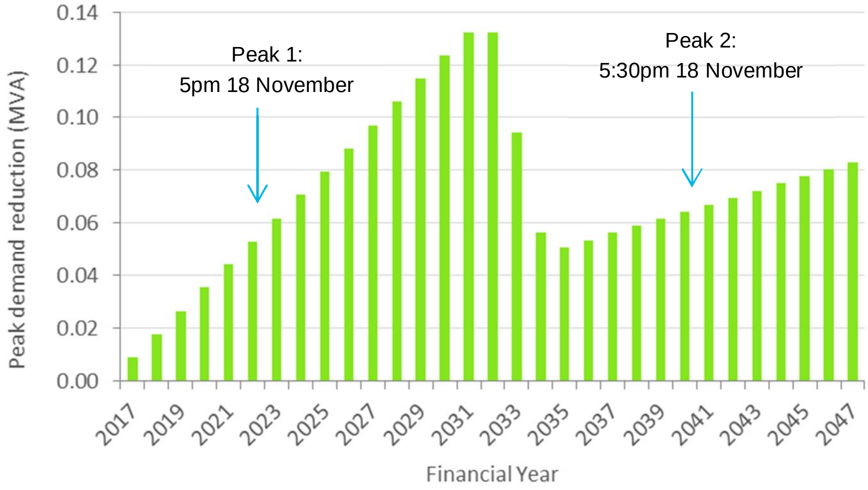


Table 29 below summarises the peak reductions observed across the three data sets for each of the LGNC solar PV uptake sensitivities in the forecast augmentation year (FY33). This table shows that there was no peak demand reduction due to the additional solar PV under Data Set 1 or 2 in this year, and marginal reductions under Data Set 3.

Table 29 Emerald peak reduction observed

	Data Set 1	Data Set 2	Data Set 3
Time of peak period (Baseline)[6]	7:30pm 14 January	8:00pm 4 January	5:00pm 18 November
Peak reduction observed	X	ü	ü
Final year of peak reduction observed	N/A	2027	2047
	Data Set 1	**Data Set 2**	**Data Set 3**
Empirical uptake (effectively 8.1% - 14.4% uptake)	No reduction	No reduction	0.10 MVA
10% PV uptake	No reduction	No reduction	0.09 MVA
20% PV uptake	No reduction	No reduction	0.14 MVA
30% PV uptake	No reduction	No reduction	0.18 MVA

5.3.2 Augmentation Deferral

Substation augmentation is deferred one year in Data Set 3 under the 30% solar PV uptake scenario. However the constraint which is deferred is not the targeted constraint (which occurs in FY33), instead the first constraint in FY21 is deferred. The target constraint does not achieve a deferral because of the high solar uptake in the Baseline scenario moving the peak period away from periods of high solar generation. This effectively removes the benefit of solar uptake in later years. Augmentation deferral results are summarised in Table 30.

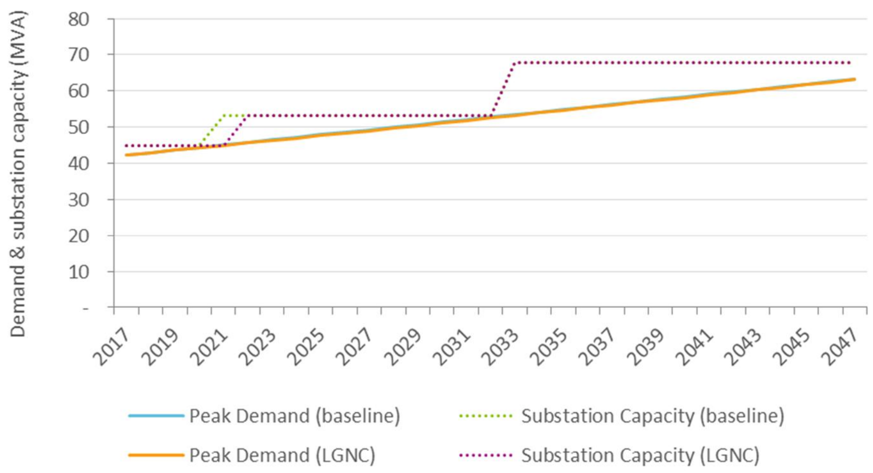
[6] The times given are the peak period in the Baseline for the forecast augmentation year. It is noted that the peak period changes with time.

Table 30 Emerald deferral observed

	Data Set 1	Data Set 2	Data Set 3
Empirical Uptake (effectively 8.1% - 14.4% uptake)	x	x	x
10% PV Uptake	x	x	x
20% PV Uptake	x	x	x
30% PV Uptake	x	x	ü
Augmentation 1 trigger (Baseline)	7:30pm 14 January FY21	5:30pm 5 January FY21	5pm 18 November FY21
Augmentation 1 trigger (LGNC, 30% PV uptake)	No change	No change	5pm 18 November FY22
Augmentation 2 trigger (Baseline)	7:30pm 14 January FY33	8pm 4 January FY33	5pm 18 November FY33
Augmentation 2 trigger (LGNC, 30% PV uptake)	No change	No change	No change

Figure 42 shows the impact of 30% solar PV uptake on augmentation timing under Data Set 3. Note that the first constraint (FY21) is deferred by one year, and the targeted constraint (in FY33) is not deferred.

Figure 42 Emerald deferral observed, 30% solar PV uptake on Baseline, Data Set 3



5.3.3 Capacity Exceedance

Similarly to Sections 5.1.4 and 5.2.3, this section provides an overview of capacity exceedance at Emerald ZS. Figure 43 shows energy at risk following the forecast augmentation year under the Baseline scenario and LGNC 10% solar PV uptake scenario. Figure 44 shows hours at risk under the same two scenarios. These figures indicate that for Data Set 1, additional solar PV has minimal benefit in reducing the energy at risk or hours at risk.

Figure 43 **Emerald energy at risk 10% solar uptake, Data Set 1**

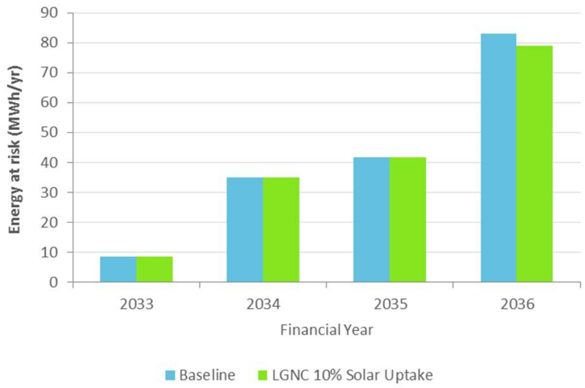


Figure 44 **Emerald hours at risk 10% solar uptake, Data Set 1**

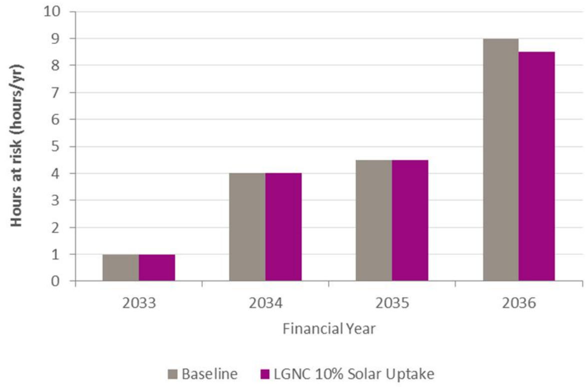


Figure 45, Figure 46 and Figure 47 provide a comparison of these two metrics under each LGNC sensitivity scenario. Similarly to previous sections, these figures serve to reinforce that solar PV can reduce energy at risk and hours at risk, but that this cannot be done reliably.

Figure 45 **Emerald energy at risk, Data Set 1**

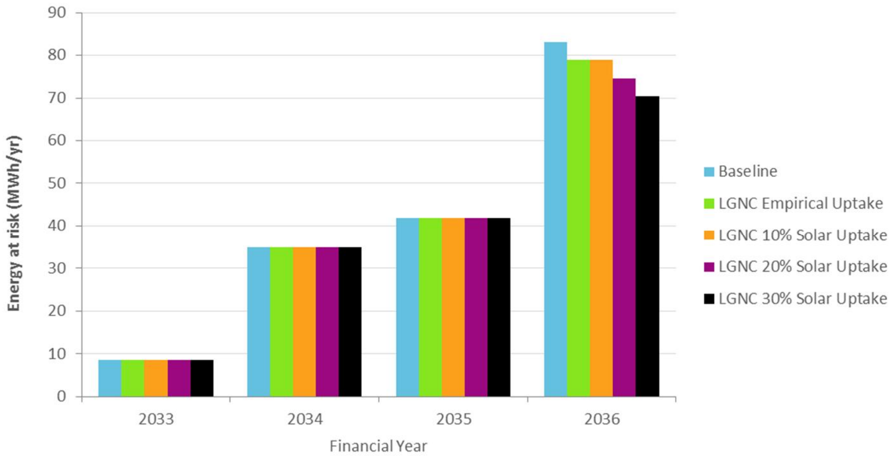


Figure 46 **Emerald energy at risk, Data Set 2**

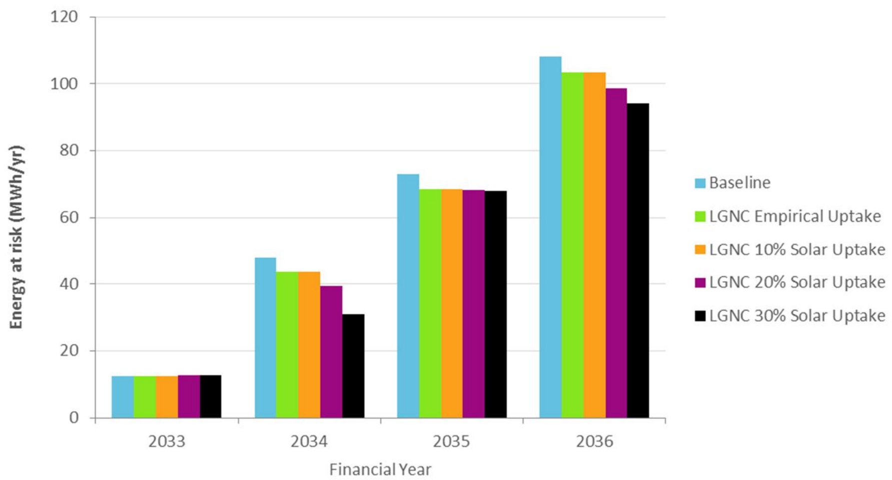
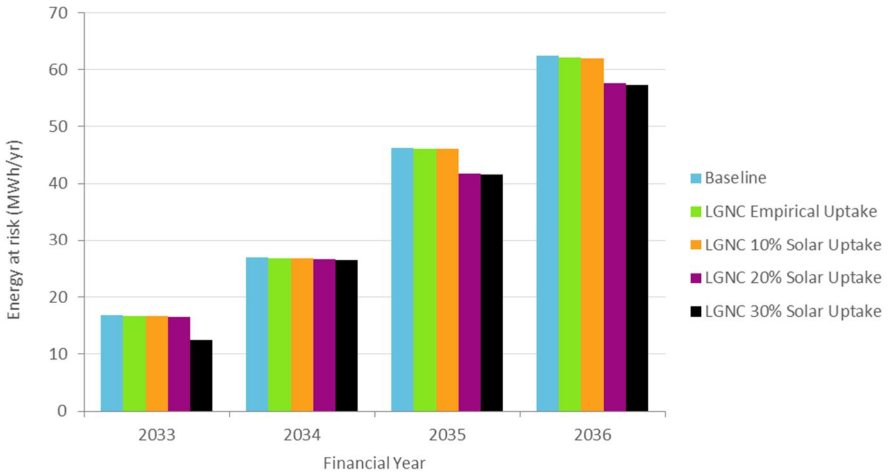


Figure 47 Emerald energy at risk, Data Set 3



5.3.4 Reverse Power Flows

A significant amount of reverse power flow events are observed at the Emerald ZS for all solar uptake sensitivities with the highest level of reverse flow experienced under Data Set 3. Therefore, Data Set 3 is detailed further in this section. Figure 48 shows the number of reverse flow events per year for 10%, 20% and 30% solar uptake as well as the reverse flow experienced in the Baseline scenario. The figure indicates that with higher levels of solar PV uptake, the number of reverse flow incidents increases dramatically.

Figure 48 Emerald – Number of reverse flow events per year, Data Set 3

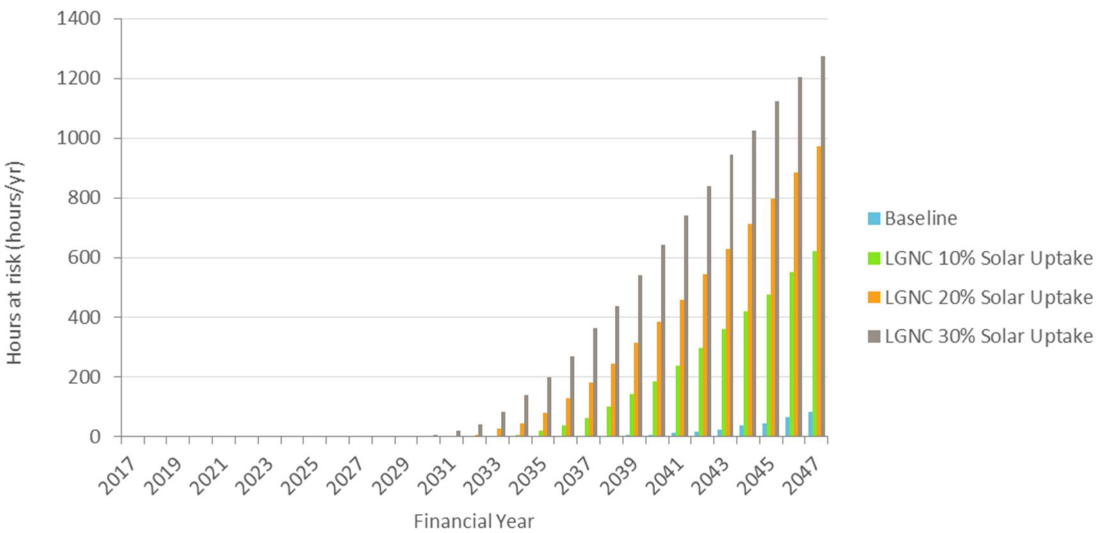


Figure 49 and Figure 50 show the peak reverse flow day for the 10% solar PV uptake scenario for Data Set 3. The figures show the daily profiles in the first year reverse flow occurs (2033) and in the final study year (2047) respectively. The potential impacts of reverse flow are discussed in Section 7.0.

Figure 49 Emerald peak reverse flow day 6 June 2033
10% solar PV on Baseline, Data Set 3

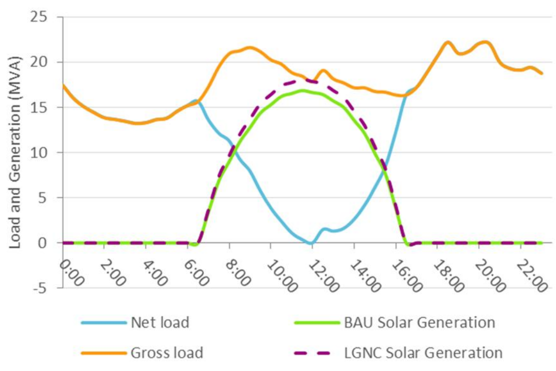
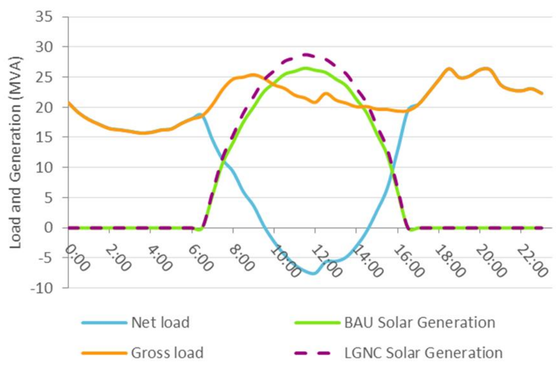


Figure 50 Emerald peak reverse flow day 6 June 2047
10% solar PV on Baseline, Data Set 3



5.4 Financial Results

This section summarises the financial impact of introducing LGNCs at each of the case studies. This includes quantifying the value of deferring substation augmentations as well as the cost of paying LGNCs. Where the modelling does not indicate that any deferral is likely, the cost of paying LGNCs is compared against the benefit of a theoretical deferral. This provides context in estimating the amount of deferral that would be necessary to counter the cost of paying LGNCs.

As with the technical results presented in this Chapter, the financial results quantify the costs and benefits of LGNC scenario relative to the Baseline scenario. The four sensitivities for the LGNC scenario are all presented.

AECOM has not imposed any costs associated with facilitating high penetrations of solar PV on the network despite the modelling indicating that reverse flows are likely in later years for Flemington ZS and Emerald ZS. As such, the estimates provided here may be considered lower boundaries of the costs of the LGNC scenario.

5.4.1 Belconnen ZS

No deferral of augmentation has been modelled at Belconnen ZS. As such, no financial benefit is captured. Hence the only difference between the scenarios is the costs of paying LGNCs. The breakdown of costs is shown in Table 31 and displayed graphically in Figure 51

Table 31 Belconnen Net Present Value Breakdown ($m)

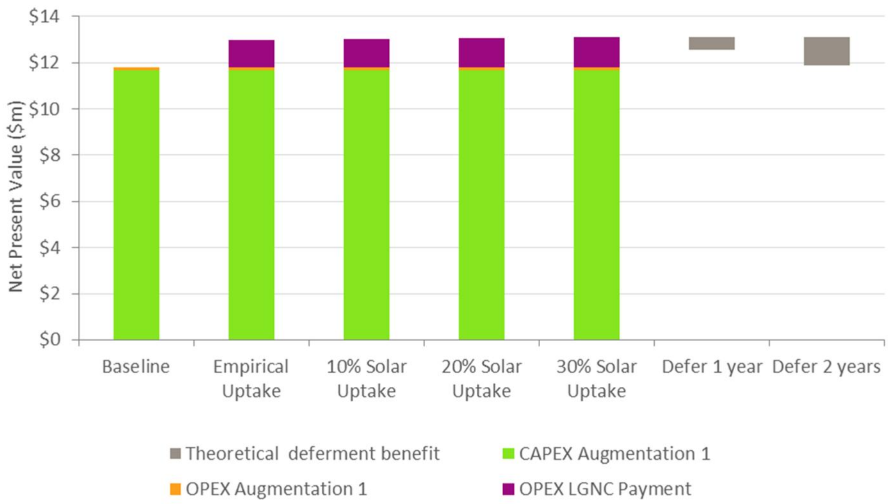
	Baseline	Empirical Uptake	10% Solar Uptake	20% Solar Uptake	30% Solar Uptake
CAPEX					
CAPEX augmentation 1	$11.67	$11.67	$11.67	$11.67	$11.67
OPEX					
OPEX augmentation 1	$0.14	$0.14	$0.14	$0.14	$0.14
OPEX LGNC payment	-	$1.18	$1.21	$1.25	$1.28
Total	**$11.81**	**$12.99**	**$13.02**	**$13.06**	**$13.10**
Change in NPV relative to Baseline	**N/A**	**$1.18**	**$1.21**	**$1.25**	**$1.28**

The cost of paying LGNCs to solar PV owners varies from $1.18 million to $1.28 million (in net present terms) depending on the level of uptake.

As noted, there is no deferral of augmentation observed for any of the targeted constraints at any of the sites, however for context, the theoretical value of one and two years deferral is shown in Figure 51.

This figure shows that the theoretical value of deferring augmentation by one year is $0.54 million and the theoretical value of deferring augmentation by two years is $1.23 million. Based on these numbers, for the value of deferral to be large enough to cancel out the cost of LGNCs (under the 10% solar PV uptake on Baseline scenario), approximately 2 years of deferral would be required for this site.

Figure 51 Belconnen NPV ($m)



5.4.2 Flemington ZS

Similarly there is no deferral of augmentation observed at Flemington ZS. As such, no financial benefit is captured. Hence the only difference between the scenarios is the costs of paying LGNCs. The breakdown of costs is shown in Table 32 and displayed graphically in Figure 52.

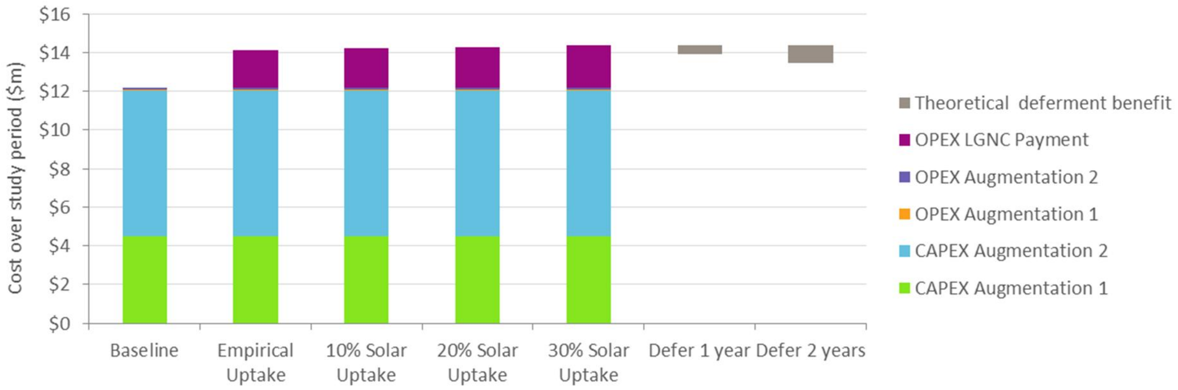
Table 32 Flemington Net Present Value Breakdown ($m)

	Baseline	Empirical Uptake	10% Solar Uptake	20% Solar Uptake	30% Solar Uptake
CAPEX					
CAPEX augmentation 1	$4.51	$4.51	$4.51	$4.51	$4.51
CAPEX augmentation 2	$7.53	$7.53	$7.53	$7.53	$7.53
OPEX					
OPEX augmentation 1	$0.06	$0.06	$0.06	$0.06	$0.06
OPEX augmentation 2	$0.09	$0.09	$0.09	$0.09	$0.09
OPEX LGNC payment	-	$1.97	$2.04	$2.11	$2.19
Total	**$12.18**	**$14.15**	**$14.21**	**$14.29**	**$14.37**
Change in NPV relative to Baseline	**N/A**	**$1.97**	**$2.04**	**$2.11**	**$2.19**

The cost of paying LGNCs to solar PV owners varies from $1.97 million to $2.19 million (in net present terms) depending on the level of uptake.

In comparison, the theoretical value of deferring investment by one year is $0.47 million and the theoretical value of deferring investment by 2 years is $0.90 million. Hence, in order to achieve parity of cost and benefit, approximately 5 years of deferral would be required to offset the cost of paying LGNCs for 10% solar uptake.

Figure 52 Flemington NPV ($m)



5.4.3 Emerald ZS

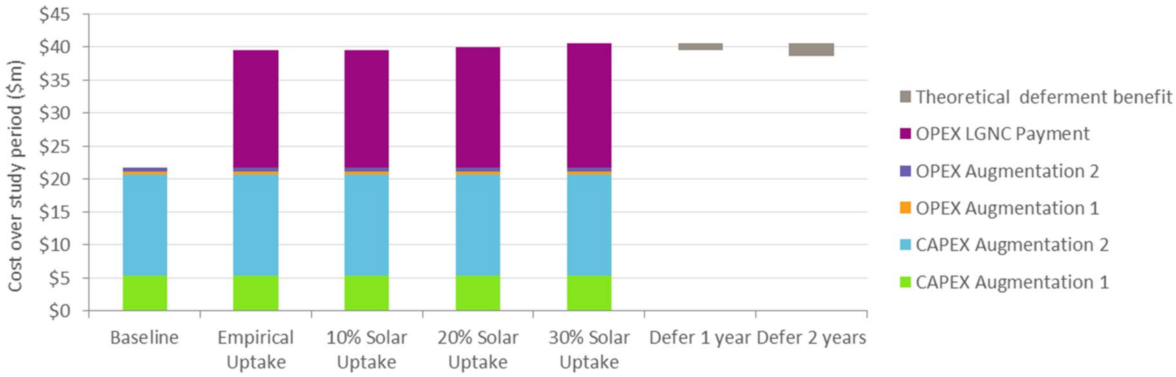
There is also no deferral of augmentation observed at Emerald ZS. As such, no financial benefit is captured. Hence the only difference between the scenarios is the costs of paying LGNCs, which is significantly higher compared with the Belconnen and Flemington ZS cases since the LGNC initial value (as calculated by Marsden Jacob from Ergon's LRMC values for its West pricing zone) is higher. The breakdown of costs is shown in Table 33 and displayed graphically in Figure 53.

Table 33 Emerald Net Present Value Breakdown ($m)

	Baseline	Empirical Uptake	10% Solar Uptake	20% Solar Uptake	30% Solar Uptake
CAPEX					
CAPEX augmentation 1	$5.39	$5.39	$5.39	$5.39	$5.39
CAPEX augmentation 2	$15.37	$15.37	$15.37	$15.37	$15.37
OPEX					
OPEX augmentation 1	$0.32	$0.32	$0.32	$0.32	$0.32
OPEX augmentation 2	$0.68	$0.68	$0.68	$0.68	$0.68
OPEX LGNC payment	-	$17.69	$17.78	$18.26	$18.73
Total	**$21.76**	**$39.45**	**$39.54**	**$40.01**	**$40.49**
Change in NPV relative to Baseline	**N/A**	**$17.69**	**$17.78**	**$18.26**	**$18.73**

The cost of paying LGNCs to solar PV owners at Emerald varies from $17.69 million to $18.73 million (in net present terms) depending on the level of uptake. Given that the cost of paying LGNCs exceeds the cost of the augmentation ($15.37 million in net present terms), this cost could not be recouped through any length of augmentation deferral.

Figure 53 Emerald NPV ($m)



5.4.4 Summary of Required Deferral to Offset LGNC Cost

While no deferral has been forecast in most sensitivity scenarios, AECOM has estimated the deferral required for each case study to offset the cost of paying LGNCs. The LGNC cost at Emerald ZS is very high, leading to a much larger deferral requirement.

Table 34 Required deferral to offset LGNC cost – 10% Solar PV Uptake

	Belconnen ZS	Flemington ZS	Emerald ZS
Cost of LGNCs (NPV) 10% solar uptake on Baseline scenario	$1.21 million	$2.04 million	$17.78 million
Deferral required to offset LGNC cost	2 years	5 years	Cost cannot be recovered through deferral

The results presented in this section, could lead some to incorrectly conclude that solar PV provides little peak reduction value. This is not the case, rather solar PV installed is already achieving the peak reduction under the Baseline scenario (this is further demonstrated in Appendix B). However, as further solar PV is installed, there is diminishing peak reduction value and, at some point, sufficient solar will be installed such that peak demand is moved outside of sunlight hours. As a result, the payment of LGNCs leads to a net cost.

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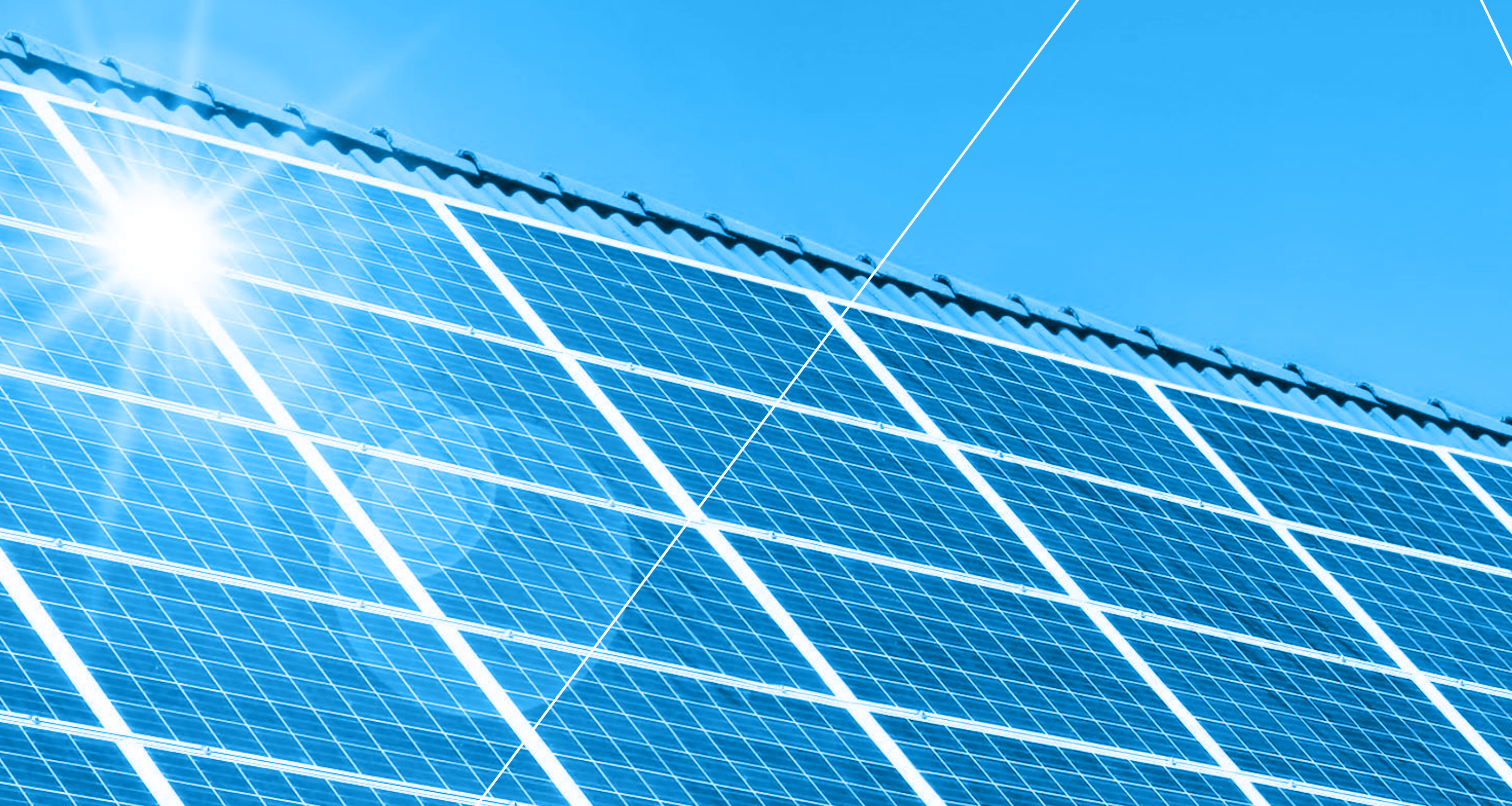
6.0 BATTERY STORAGE



6.0 Battery Storage

One common result observed in this study was that increasing penetrations of solar PV are shifting peak demand periods into the evening period when there is no solar generation. For solar PV as a standalone technology, there is limited ability to reduce peak demand. However, when combined with battery storage, there is an improved ability to match solar generation with peak demand periods.

This section sets out the assumptions in AECOM's modelling of battery storage (refer to Section 6.1), and the key results regarding peak demand reduction (refer to Section 6.3). In order to show the relative impact of battery storage, compared to stand-alone solar PV, AECOM has shown the results relative to a "Zero Solar" scenario. This scenario is defined in Section 6.2.

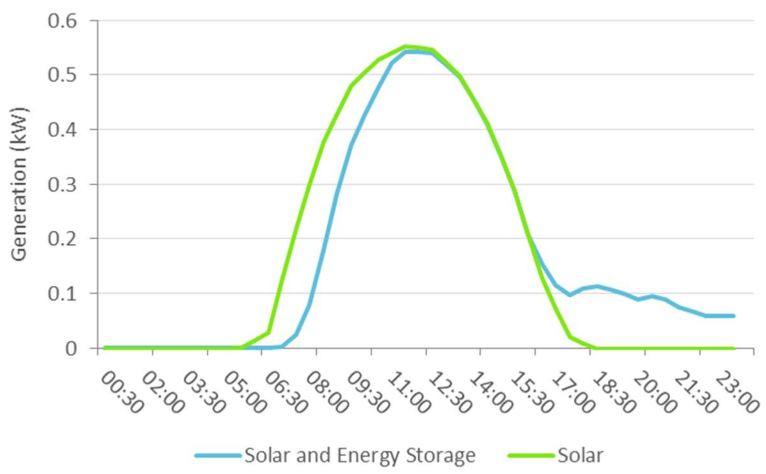
6.1 Battery Assumptions

This section investigates the impact of storage on peak demand by pairing a proportion of solar PV systems with storage. To model the impact of battery storage, AECOM has focused on the "self-consumption" charging regime that may be used by households to reduce their imports from the grid. This charging regime is typically incentivised through flat consumption tariff structures. While time of use and maximum demand tariff structures can incentivise different charging regimes, they have not been included in this analysis due to the significant uncertainty of the timing and structures of such tariffs in the long term.

Under the modelled charging regime, solar PV is first used to charge the battery; any remaining generation is then self-consumed or exported if there is insufficient local demand. From 4pm, the battery is permitted to discharge to meet the household's load. From this time onwards, solar PV is first used for self-consumption, with any shortfall being made up by battery storage. The modelling assumes pairing of a 5kW solar PV with 3kW / 7kWh battery and a selection of example household demand profiles from the Ausgrid 300 homes data set. This facilitated the development of a 30-minute, 365 day generation profile for each site.

Figure 54 shows the average generation profile for the paired solar-storage system. The chart shows the profile on a "per kW-installed solar" basis. Compared to a pure solar profile, the paired solar-storage system has lower morning generation, as well as a long evening tail. The output of the evening tail is quite low due to varying levels of customer demand in this period, as well as instances where the battery was not fully charged during the day.

Figure 54 Emerald average solar and solar paired with ES profiles, Data Set 1



6.2 Zero Solar Scenario

The "Zero Solar" scenario examines the peak load with zero installed solar capacity. The purpose of considering the Zero Solar scenario is to show the relative impact of battery storage paired with solar PV against the impact of solar PV alone. The Zero Solar scenario enables this to be done in a clear and meaningful way.

The Zero Solar scenario is equivalent to the gross solar profile, meaning that it can be calculated by removing the solar PV component from the Baseline Scenario in any given year. Typically, the impact of this is to increase the maximum demand value and shift the time of the maximum demand period. These Zero Solar peak demand periods are presented in Table 35. The Zero Solar scenario peaks are typically between 1pm and 6pm in summer, with the exception of Belconnen Data Set 3 where the peak period is 6:30pm in winter.

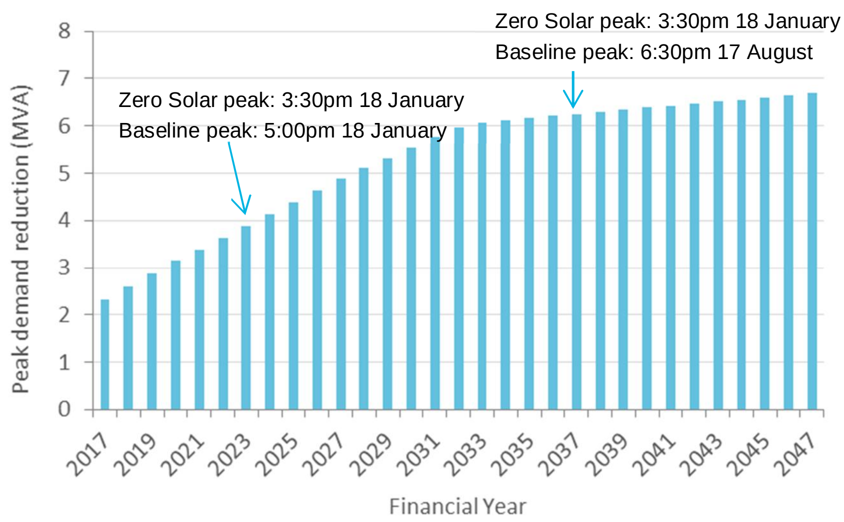
Table 35 Zero solar scenario peak demand periods

	Data Set 1	Data Set 2	Data Set 3
Belconnen	3:30pm 18 January	5:00pm 3 February	6:30pm 30 June
Flemington	3:00pm 29 November	1:00pm 16 January	6:00pm 22 January
Emerald	5:00pm 14 January	2:30pm 20 January	5:00pm 18 February

6.2.1 Impact of Baseline Solar

There is considerable peak reduction observed when comparing the Baseline scenario with the Zero Solar scenario. Figure 55 shows the peak reduction achieved and indicates that the current day level of peak reduction due to solar PV is in the order of 2.3MVA at Belconnen.

Figure 55 Belconnen peak reduction (comparing Baseline with Zero Solar) Data Set 1



For further details comparing the Baseline and Zero Solar scenarios, refer to Appendix B.

6.3 Peak Reduction

To demonstrate the value of storage, AECOM has compared the peak reduction achieved by the Baseline scenario against the peak reduction achieved by paring Baseline levels of solar PV with storage. The level of peak reduction has been calculated relative to the Zero Solar scenario for each scenario. This has been done in order to give context to the observed impact of battery storage, as its impact can be seen relative to the impact of Baseline solar PV.

The following scenarios have been compared to the Zero Solar scenario:

Table 36 Energy storage uptake scenarios

Scenario	Description
Baseline	Baseline solar PV uptake with no battery storage
25% pairing	Baseline solar PV with 25% of PV systems paired with battery storage (15kW/35kWh storage for every 100kW of solar PV)
50% pairing	Baseline solar PV with 50% of PV systems paired with battery storage (30kW/70kWh storage for every 100kW of solar PV)

Scenario	Description
75% pairing	Baseline solar PV with 75% of PV systems paired with battery storage (45kW/105kWh storage for every 100kW of solar PV).

The storage pairing proportions are relative to all installed solar PV, not just new installations. The three scenarios are not meant to act as realistic forecasts; rather, they are used to show the impact of the technology.

6.3.1 Belconnen Peak Reduction

Figure 56, Figure 57 and Figure 58 show the peak reduction (relative to the Zero Solar scenario) observed at Belconnen ZS across the three data sets. Figure 56 (Data Set 1) indicates that Baseline solar PV can reduce peak demand by up to 6.7MVA and that 50% pairing of battery storage can increase this to 9.6MVA. In contrast, standalone solar PV provides no peak reduction in Data Set 3, but 50% pairing of battery storage can provide 1.5MVA of peak reduction.

Figure 56 **Belconnen peak reduction with battery storage Data Set 1**

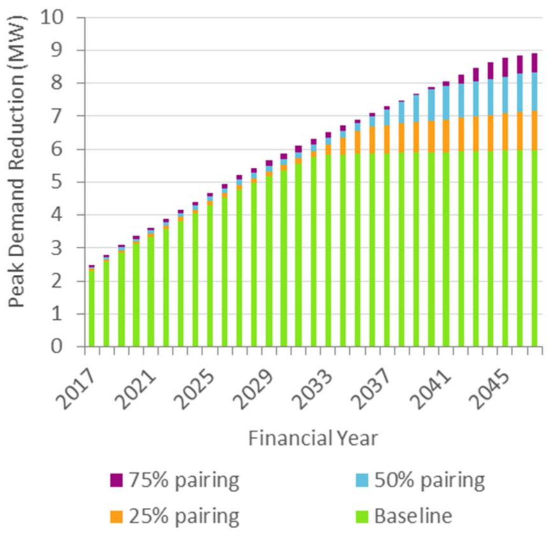


Figure 57 **Belconnen peak reduction with battery storage Data Set 2**

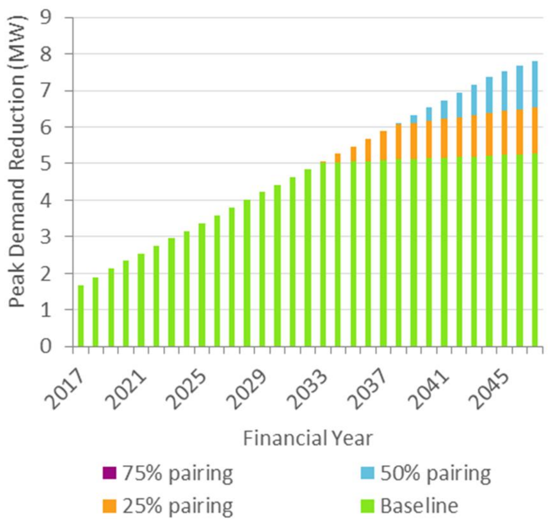
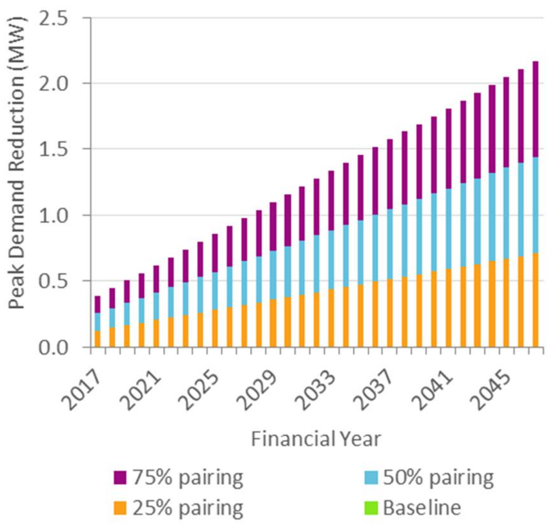


Figure 58 **Belconnen peak reduction with battery storage Data Set 3**



6.3.2 Flemington Peak Reduction

Figure 59, Figure 60 and Figure 61 show the same comparison for the Flemington ZS. These figures show that for all data sets, battery storage reduces peak demand. It is also interesting to note that or Data Set 3 (Figure 61), where standalone solar provides a relatively smaller contribution to peak demand, battery storage provides a relatively larger contribution, effectively hedging the contribution of solar PV.

Figure 59 Flemington peak reduction with battery storage Data Set 1

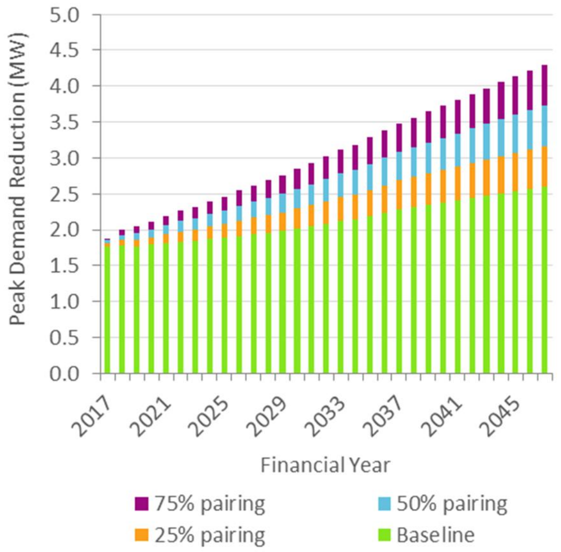


Figure 60 Flemington peak reduction with battery storage Data Set 2

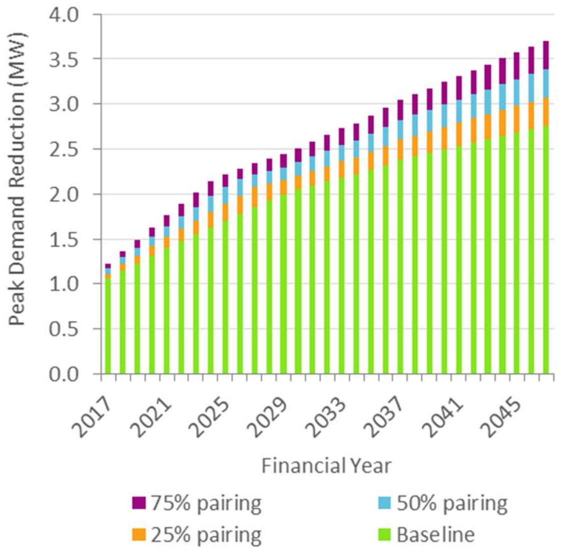
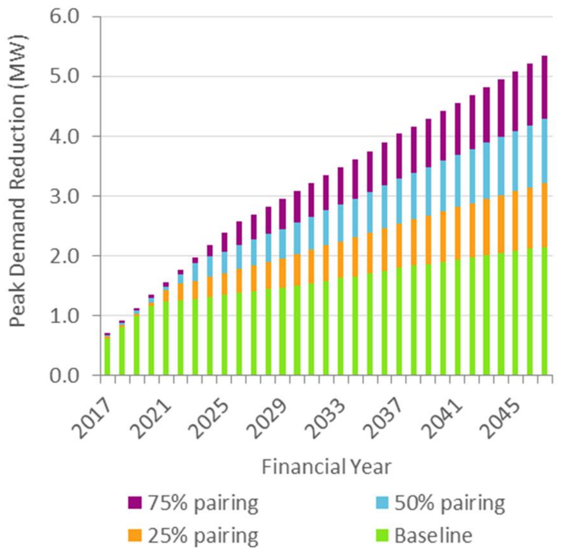


Figure 61 Flemington peak reduction with battery storage Data Set 3



6.3.3 Emerald Peak Reduction

Similarly, Figure 62, Figure 63 and Figure 64 show the peak demand reduction for Data Sets 1, 2 and 3 at Emerald ZS. For all cases battery storage provides peak demand reduction and increased levels of battery storage provides increased levels of demand reduction. Once again, the hedging value of battery storage is clear in Figure 62 where battery storage appears to compensate for the small peak reduction provided by standalone solar.

Figure 62 Emerald peak reduction with battery storage Data Set 1

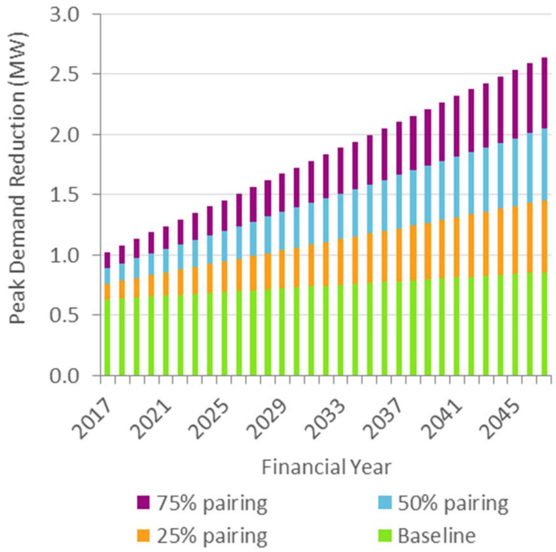


Figure 63 Emerald peak reduction with battery storage Data Set 2

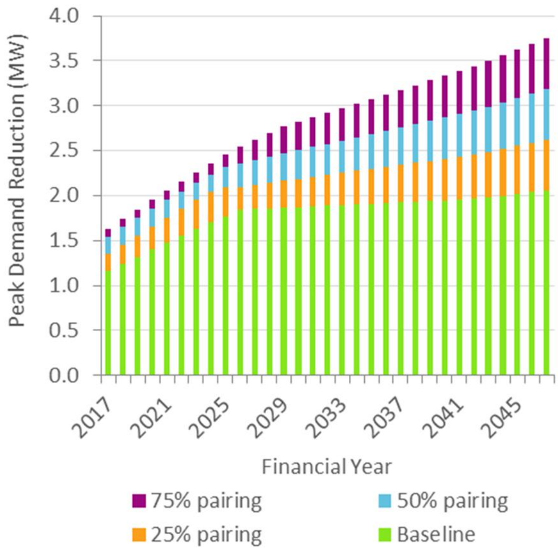
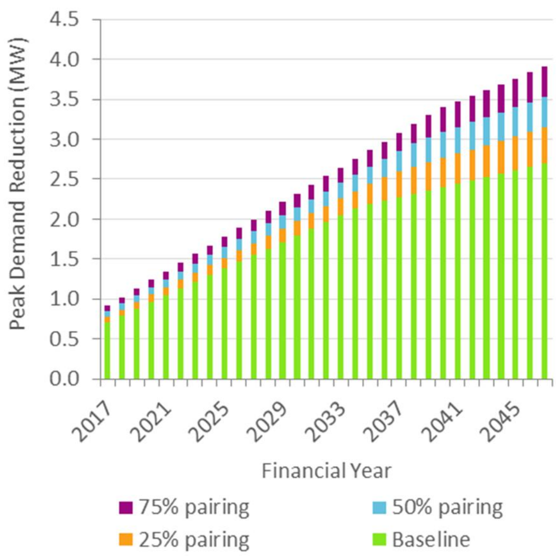


Figure 64 Emerald peak reduction with battery storage Data Set 3



6.4 Augmentation Deferral

This section considers whether the peak demand reductions achieved by pairing Baseline solar uptake with energy storage could defer network augmentations relative to the Baseline scenario.

6.4.1 Belconnen ZS

At the Belconnen ZS, the reduction in peak demand caused by energy storage is not large enough to defer augmentation as shown in Table 37. This is because the reduction in peak demand is not large enough to take the maximum demand event below the 63MVA trigger. This result was common to all three data sets and battery uptake sensitivity scenarios.

Table 37 Belconnen deferral observed

	Data Set 1	Data Set 2	Data Set 3
25% battery pairing	0 years	0 years	0 years
50% battery pairing	0 years	0 years	0 years
75% battery pairing	0 years	0 years	0 years
Peak time in augmentation trigger year	5:00pm 18 January FY19	5:30pm 3 February FY19	6:30pm 30 June FY19

For Data Sets 1 and 2, the addition of storage has minimal impact in FY19 because solar PV is already generating during the peak period and the self-consumption charging regime does not trigger the battery to discharge unless a customer's demand exceeds their solar generation. In Data Set 3, battery storage reduces peak demand by up to 0.5MVA (75% energy storage) in FY19; however this was not by enough to reduce the peak period below the 63MVA threshold.

6.4.2 Flemington ZS

At the Flemington ZS, the reduction in peak demand caused by energy storage is generally not large enough to defer augmentation as shown in Table 38. The one exception occurs for Data Set 3 when there is 75% battery pairing. In this case, augmentation is deferred by one year.

Table 38 Flemington deferral observed

	Data Set 1	Data Set 2	Data Set 3
25% battery pairing	0 years	0 years	0 years
50% battery pairing	0 years	0 years	0 years
75% battery pairing	0 years	0 years	1 year
Peak time in augmentation trigger year	7:30pm 18 February FY23	7:00pm 28 January FY23	6:30pm 4 June FY23

Data Sets 1 and 2 contribute up to 0.5MVA (75% energy storage) reduction in peak demand; however this was not sufficient to reduce the peak period below the 40.8MVA threshold. Data Set 3 achieved 0.6MVA reduction in peak demand in the 75% energy storage sensitivity, which was sufficient to trigger a one year deferral.

6.4.3 Emerald ZS

At the Emerald ZS, the reduction in peak demand caused by energy storage is significant enough to defer augmentation as shown in Table 39 under all cases except one. As shown, the only case in which augmentation deferral is not observed is Data Set 3 with only 25% battery pairing.

Table 39 Emerald deferral observed

	Data Set 1	Data Set 2	Data Set 3
25% battery pairing	1 year	1 year	0 years
50% battery pairing	1 year	1 year	1 year
75% battery pairing	2 years	2 years	1 year
Augmentation 1 trigger (Baseline)	7:30pm 14 January FY21	5:30pm 5 January FY21	5pm 18 November FY21
Augmentation 2 trigger (Baseline)	7:30pm 14 January FY33	8pm 4 January FY33	5pm 18 November FY33

6.5 Peak Reduction Potential

In this battery analysis, AECOM has assumed the use of a "self-consumption" charging regime, which is designed to reduce customers' imports from the grid (presented in section 6.1). However, in terms of reducing peak demand, this charging regime is an inefficient use of battery capacity.

To demonstrate this point, AECOM has calculated the expected battery capacity at each site in the relevant augmentation year. In theory, if batteries were controlled to provide grid support through peak demand reduction, then the total installed capacity could be available to reduce peak demand (depending on the duration of the peak period). However, under the self-consumption charging regime, the peak reduction achieved by batteries is only a small fraction of the total installed capacity.

This is demonstrated in Figure 65, Figure 66 and Figure 67 which compare the peak reduction achieved by the self-consumption charging regime against the total installed battery capacity. From examining these figures, it can be concluded that the peak reduction potential of battery storage far exceeds the peak reduction achieved for each site in the forecast augmentation year. For example, at Belconnen the peak reduction achieved by battery storage under self-consumption is zero in Data Set 2. This is because the peak period falls during daylight hours when there is plentiful solar generation and no incentive for consumers to discharge their battery.

Figure 65 Belconnen battery storage capacity compared with peak reduction (FY19)

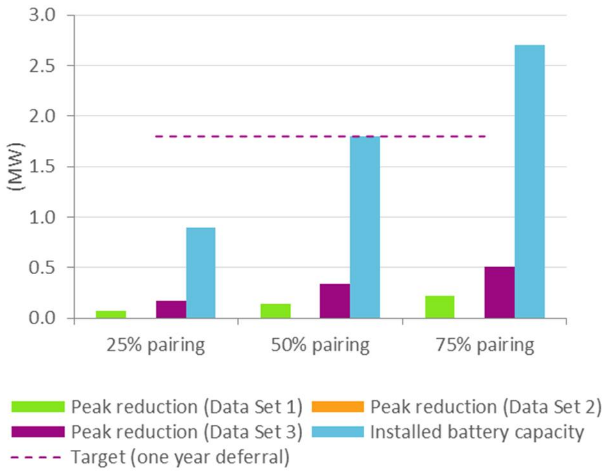


Figure 66 Flemington battery storage capacity compared with peak reduction (FY23)

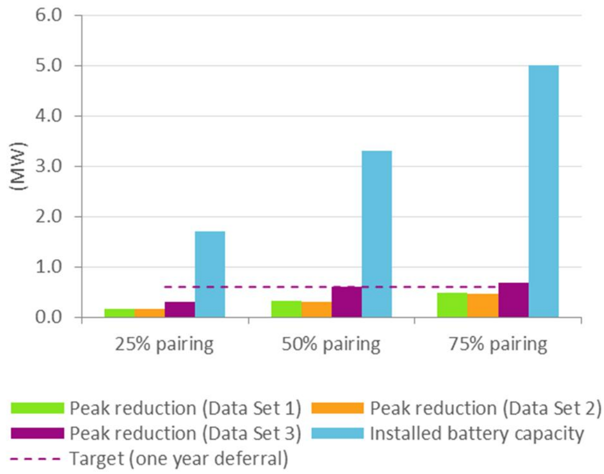
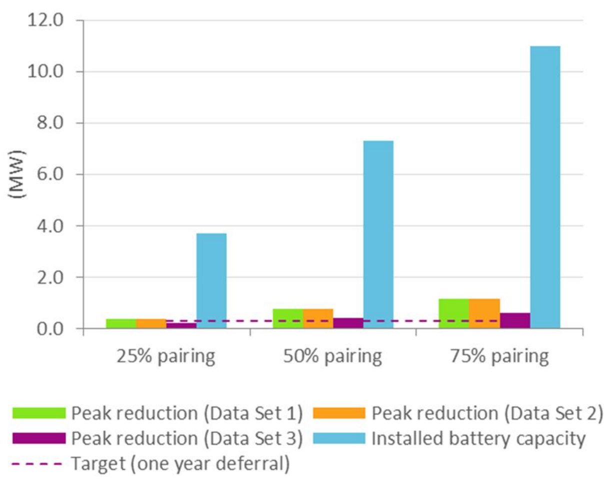


Figure 67 Emerald battery storage capacity compared with peak reduction (FY33)



A second key conclusion can be drawn from these figures; that the installed battery storage capacity has the capability to defer network augmentation. The horizontal magenta dashed line represents the required (or "target") level of peak reduction which needs to be realised to ensure augmentation deferral of one year. It can be clearly observed that the required peak reduction varies significantly between the three sites, and that in most cases the installed battery capacity exceeds the peak reduction requirement. In particular, for both Flemington and Emerald, only 25% pairing of battery storage could result in augmentation deferral if the full installed capacities were utilised.

6.6 Key Findings

The analysis shows that larger reductions in peak demand can be achieved when solar is paired with battery storage. However, the degree of peak reduction is highly dependent on the peak day profile, particularly given that the batteries only charge from solar generation. For some peak days the solar and battery storage profile is well suited to reducing the peak load, whereas on others, the solar and battery storage profile is not well suited. This result is due to the assumptions used in the solar-pairing self-consumption charging regime and it is noted that the full capability of battery storage is not realised by the self-consumption charging regime.

Overall, the results demonstrate a number of key observations:

- Battery storage is more reliable than stand-alone solar in providing reductions in peak demand. For example, Belconnen Data Set 3 (Figure 58) shows peak reduction from storage despite there being no reduction from solar PV.
- Under the self-consumption charging regime, no peak reduction is provided by battery storage (above that of solar PV) until the peak period is shifted outside sunlight hours.
- Under the self-consumption charging regime, the ability of battery storage to provide peak reduction varies substantially, depending on the data set. In addition, the peak demand achieved by the self-consumption charging regime is far smaller than the technical capability of the batteries. Typically, the technical capability of batteries for peak demand was 5-10 times larger than the peak demand reduction achieved under self-consumption. This result demonstrates the potential for using smarter charging regimes coupled with appropriately structured incentives.
- Peak reduction due to the use of battery storage under the examined charging regime can result in augmentation deferral. However, significant levels of peak demand reduction are required to offset forecast growth in peak demand rates. Of the case studies considered, only Emerald demonstrated sufficient reduction in peak demand across all three data sets. However, to ensure deferral occurred across each Data Set 1, 2 and 3, 50% battery storage pairing was required. It is anticipated that less storage would be required to achieve network deferral if the full technical capability of batteries could be reliably utilised.

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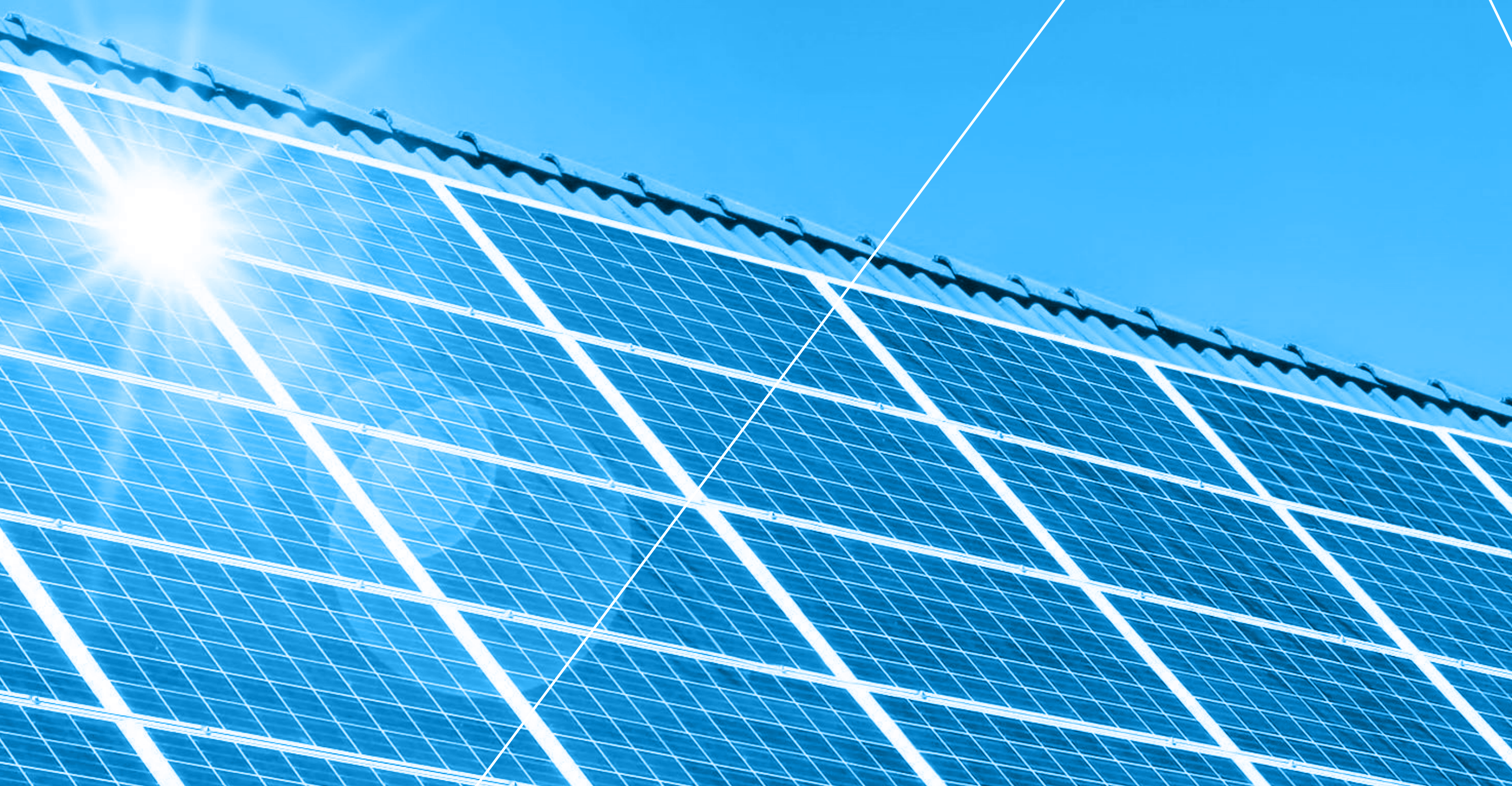
7.0 TECHNICAL IMPACTS OF HIGH PENETRATION SOLAR



7.0 Technical Impacts of High Penetration Solar

This report has focused on the ability of embedded solar PV to reduce demand through zone substations. However, high penetrations of embedded solar PV can also lead to several technical challenges for networks. These technical challenges can require significant investment, which has been excluded from the financial analysis presented because it is difficult to quantify accurately without completing detailed network modelling. Where possible, this chapter provides indicative costs. This chapter discusses several key issues, which are summarised in Table 40.

Table 40 Summary of technical issues caused by high penetrations of solar PV

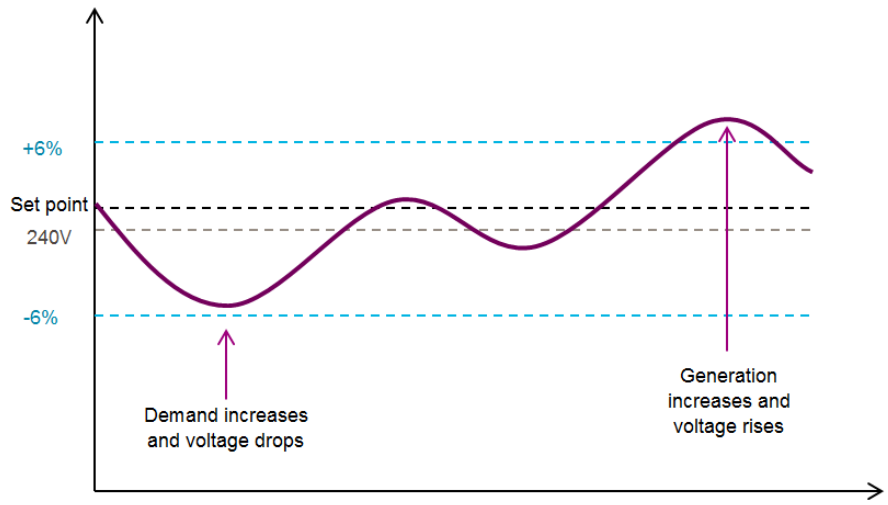
Issue	Description	Potential Network Response
Permissible voltage range	Networks are required to deliver power to customers within a specific voltage range. If power is delivered outside these limits it can impact customers in various ways including premature failure of appliances and house fires.	- Changes to transformer tap settings - Upgrade transformers - Install bidirectional voltage regulators on long feeders - Upgrade conductors - Install new technologies - Incentivise/mandate provision of reactive power from solar PV inverters
Phase imbalance	Voltage imbalance occurs when there is considerably more load or generation on one specific phase compared with the other two phases, leading to different voltages across each phase.	As above, plus: - Modifications of connections to re-balance the network
Harmonic frequencies generated by inverters	Increased penetration of solar PV can increase harmonic distortion on the network, which can cause network components and end user loads to become overloaded, damaged or to malfunction.	Increased connection requirements regarding permissible levels of harmonic emissions. This may include improved inverter quality or the use of harmonic filters (cost for party installing, rather than the network).
Reverse flow	Problems may arise in terms of mal-operation of protection systems (depending on the specific design characteristics).	- Voltage regulators (common on long rural feeders and at substations with a mix of long and short feeders) may need to be upgraded to bidirectional - At substations, protection systems may need upgrades, e.g. directional overcurrent protections systems would unnecessarily trip in the event of reverse flow
Loss of mains – failure of anti-islanding protection	High penetration of solar PV may lead to failure of protection equipment to recognise loss of mains power due to the high levels of local generation.	More onerous protection requirements installed with each solar PV system (cost for party installing, rather than network).

Many of these challenges are not unique to high penetration solar PV networks. Challenges such as maintaining voltage within acceptable ranges, and balanced across phases are common technical challenges addressed by networks. However, high penetrations of solar PV may make these challenges more difficult to address.

The most notable technical challenge relates to maintaining voltage levels within acceptable voltage limits (typically ± 6%, or 225.6 – 254.4V for residential customers). Traditionally, networks have been designed and operated based on the premise that voltage reduces over the length of the conductor as the load source gets further away from the power source. The introduction of solar PV can complicate this premise, with large amounts of solar PV generation raising the voltage. Traditionally DNSPs have only needed to account for load variation and have not had to manage significant generation within the distribution network. To manage load variation, DNSPs have traditionally been able to change the transformer tap settings. In particular, DNSPs have set transformers to operate at a voltage range which is above the target voltage (target voltage generally 240V) so that during peak demand the voltage does not fall below the lower voltage limit.

However, the emergence of embedded generation in distribution networks means that networks have to account for both increases and decreases in voltage relative to the set point, making it more difficult to achieve the voltage tolerance range. This concept is depicted in Figure 68.

Figure 68 Impact of load and generation changes on voltage



The consequences of voltage rise include:

- premature failure of appliances (immediately or over a prolonged time frame, depending on the appliance and the characteristics of the voltage rise)
- solar PV inverters may trip off frequently.

There are several different technical solutions for voltage rise, some of which are briefly described in Table 41. The most appropriate solution will vary on a site-specific basis.

Table 41 Technical solutions to voltage rise [30]

Solution	Description
Change transformer tap settings	- Manually change the transformer tap settings - The “set point” voltage is then reduced - Under voltage can become a problem if low generation or high demand conditions occur
Upgrade transformer	- When upgrading a transformer, change the “set point” voltage
Install a new transformer	- Where conductor lengths are significant (>600m) a new transformer may be required
Upgrade conductors (“re-conductoring”)	- Old high impedance conductors can exacerbate voltage rise issues - Replacing with new conductors can reduce voltage rise
Install new technologies	**OLTC** (On load tap changer) - Can change taps without temporarily cutting off supply to load **STATCOMs** (static synchronous compensator) - STATCOMs are power electronic devices which can provide reactive

Solution	Description
	power support **Capacitors** Installed either on poles or in substations - Provides reactive power support to networks

Currently, the preferred solution for managing voltage rise is through changing transformer tap settings. However, with increasing penetrations of solar, re-adjusting tap setting may not be able to account for the increasing amount of voltage variation between periods of peak generation and peak demand. As such, low voltage challenges may arise in attempting to address voltage rise.

Realistically, technical solutions should be determined on a site-by-site basis reflecting site-specific characteristics. However, as a rough guide, Energex has indicated which network solutions are appropriate for increasing levels of solar PV penetration, as shown in Table 42. Generally, higher levels of solar PV penetration correspond to more costly network solutions.

Table 42 Network options for addressing technical issues caused by varying levels of solar PV penetration [30]

Solar PV Penetration Level	Network Options
From 30% to 70%	1. Balance of PV load 2. Change transformer tap
From 40% to 100%	3. Both 1 and 2 above 4. Upgrade transformer 5. New additional transformer or voltage regulators 6. Re-conductor mains
From 100% to 200%	7. 1 to 6 above 8. New technology (on load tap transformer, LV regulator, Statcom)

The solar PV penetration levels in Table 42 above represent the ratio of installed capacity relative to the distribution transformer (kiosk transformer) capacity supplying a low voltage area. Using this definition, the three case studies will likely fall in the 40% to 100% range, although significant variation is likely to occur within localised areas serviced by the zone substation.

In addition to the costs associated with the network solutions, there is an additional cost for networks in terms of identifying and monitoring the power quality challenges. As an example, this cost was highlighted by Energex in its 2015 regulatory proposal, where it requested $25 million in CAPEX for monitoring of voltage issues caused by solar PV as well as an additional $13.4 million for remediation of identified issues[7]. This monitoring program targeted 3,600 distribution transformers, at a cost of nearly $5,000 per distribution transformer [30]. If similar monitoring were to be implemented at every distribution transformer in each of the three case studies, this could equate to between $400K and $750K of capital cost.

Energex also estimated the cost of remediation at $16,000 per site for network areas with penetrations higher than 25% [30]. If similar remedial action (see Table 42) were to be implemented at every distribution transformer in each of the three case studies, this could equate to between $1.4 million and $2.4 million of capital cost. Considering the current solar PV installation capacity and forecast uptake rate, these costs would likely be encountered in the next 10 years. However, as higher penetrations are achieved over time, more expensive remedial action may be required.

[7] It is noted that in its Final Determination, the AER only approved $25.3 million, 33 percent less than the $38.4 million requested by Energex [36]

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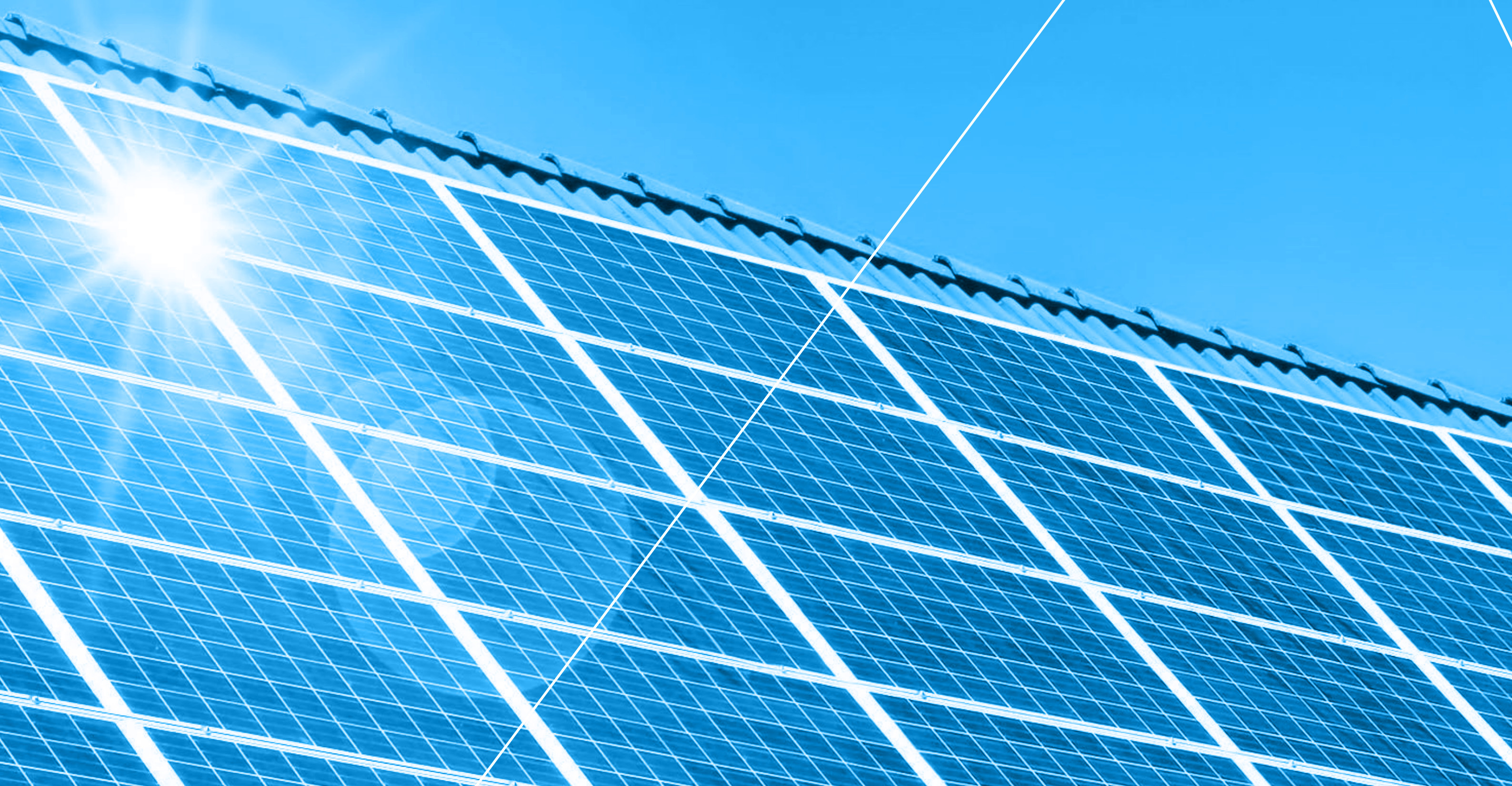
APPENDIX A SOLAR PV PROFILE NORMALISATION



Appendix A Solar PV Profile Normalisation

In order to accurately model the load profile impact of solar PV, it is vital to have accurate solar PV generation profiles at each case study location. AECOM has estimated solar PV generation profiles using historic satellite irradiation data sourced from the Bureau of Meteorology and solar modelling tool PVsyst.

Noting that rooftop systems are inherently diverse in efficiency (e.g. tilt, shading, soiling, and azimuth), AECOM has applied a correction factor to better align the modelled generation with the performance of real world rooftop systems. The correction factor was calculated by correlating AECOM's modelled PVsyst profile with 30 minute generation data from 300 rooftop solar systems in Ausgrid's network (Ausgrid 300 homes). AECOM has used BOM satellite irradiation data that is co-incident with Ausgrid's solar PV generation data to account for natural variations in irradiation.

A comparison of the two average profiles is shown below for data from financial years 2012 and 2013.

Figure 69 Comparison of solar generation profile from PVsyst modelling with real world solar rooftop data (FY2012)

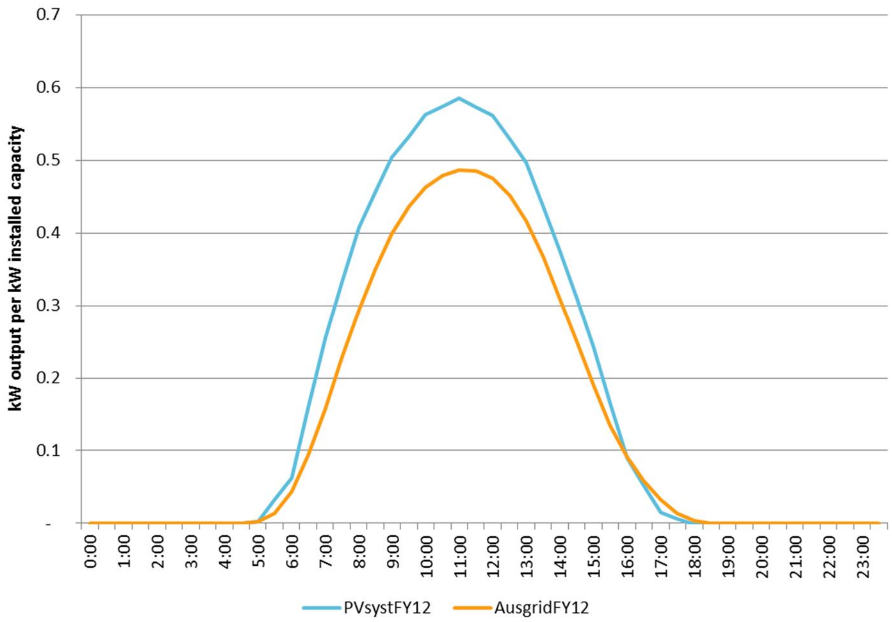
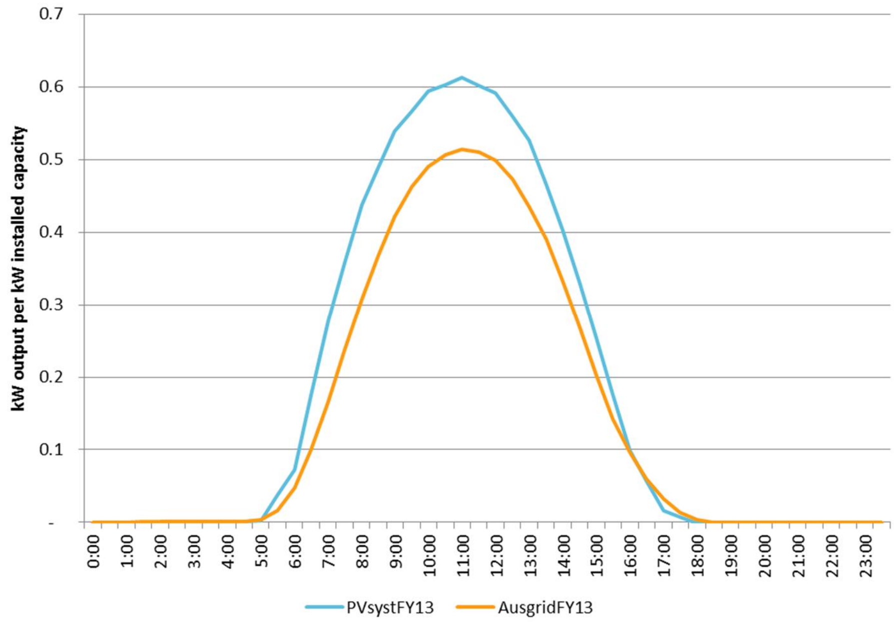


Figure 70 Comparison of solar generation profile from PVsyst modelling with real world solar rooftop data (FY2013)



Both charts show good correlation in shape, but the real world data (Ausgrid) is approximately 16% lower than the modelled data. As such, AECOM has used a correction factor of 0.84 to scale our modelled solar generation profiles to make them more representative of the diversity of household systems. A comparison of the generation profiles after application of the correction factor is provided in Figure 71 and Figure 72

Figure 71 Comparison of solar generation profile from PVsyst modelling (with correction factor applied) against Ausgrid's measured solar rooftop data (FY2012)

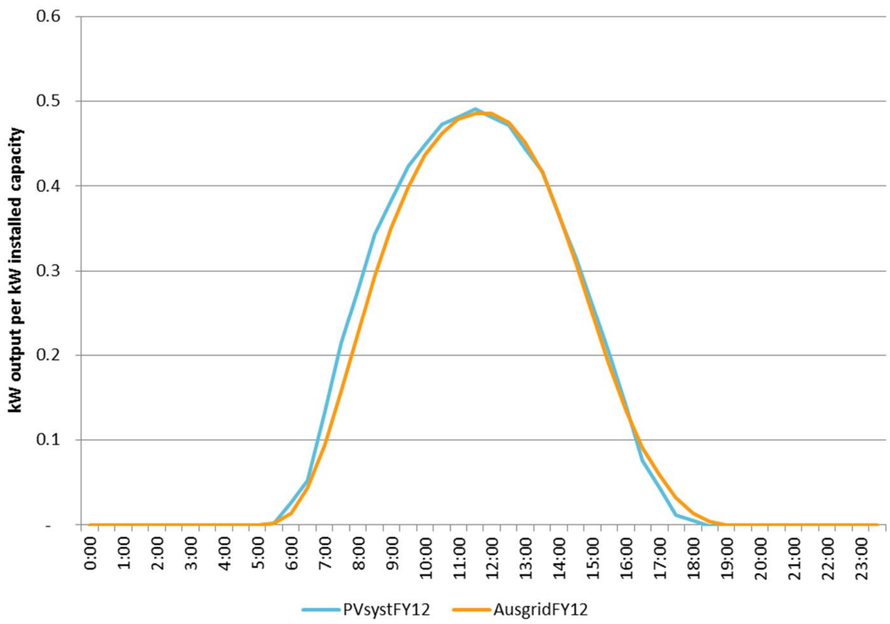
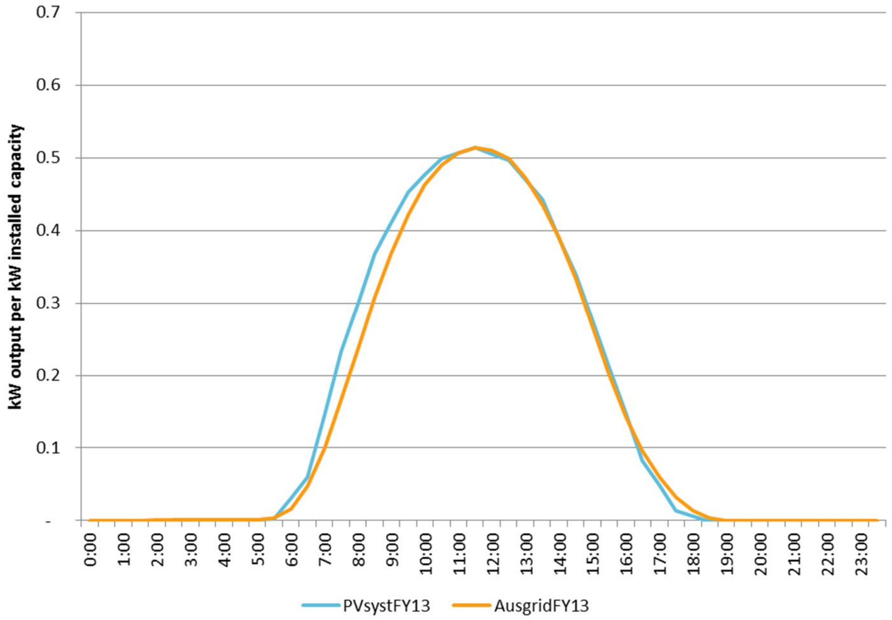


Figure 72 Comparison of solar generation profile from PVsyst modelling (with correction factor applied) against Ausgrid's measured solar rooftop data (FY2013)



Module orientation

The directional orientation of solar PV modules has a significant impact on the expected electrical generation and profile which the system is able to provide. As well as impacting the total amount of energy yield that a system can deliver in a year, module orientation also impacts the time of day which the system generates power.

To date the main stream school-of-thought has been to install solar systems with a north-facing orientation, in order to maximise total electricity generation. Similarly, the solar PV generation profiles used in AECOM's Demand Profile Modelling were based on a north-facing orientation.

However, AEMO's recent National Electricity Forecasting Report (NEFR) stated that, in the future, up to 10% of rooftop solar PV capacity could be west-facing to better align rooftop PV with peak electricity costs. West-facing solar PV is commonly cited as providing greater network benefits than north-facing PV, due to greater alignment between the generation profile and peak demand periods.

In order to investigate the capabilities of west-facing solar PV, AECOM has modelled the output of a rooftop solar PV system for both west-facing and north-facing orientations. The average daily generation profiles for winter (July) and summer (January) are shown in Figure 73 and Figure 74.

Figure 73 Winter generation profile comparison

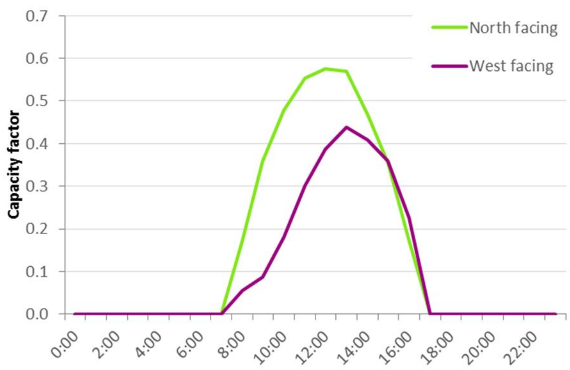


Figure 74 Summer generation profile comparison

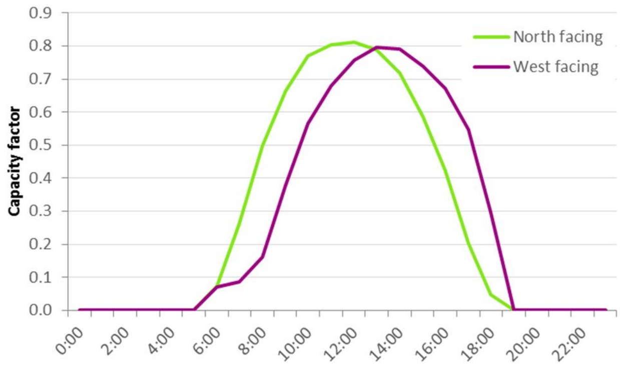


Figure 73 indicates that west-facing solar PV is likely to provide limited value in meeting a winter afternoon or morning peak, and generally produces substantially less energy over the day.

Figure 74 demonstrates that west-facing solar PV may provide greater support for meeting an afternoon peak, if peak demand occurs after 2pm. While the west facing system does not materially extend the hours of generation, there is a significant increase in the magnitude of the evening generation which would increase its contribution to peak demand (if it falls within this period).

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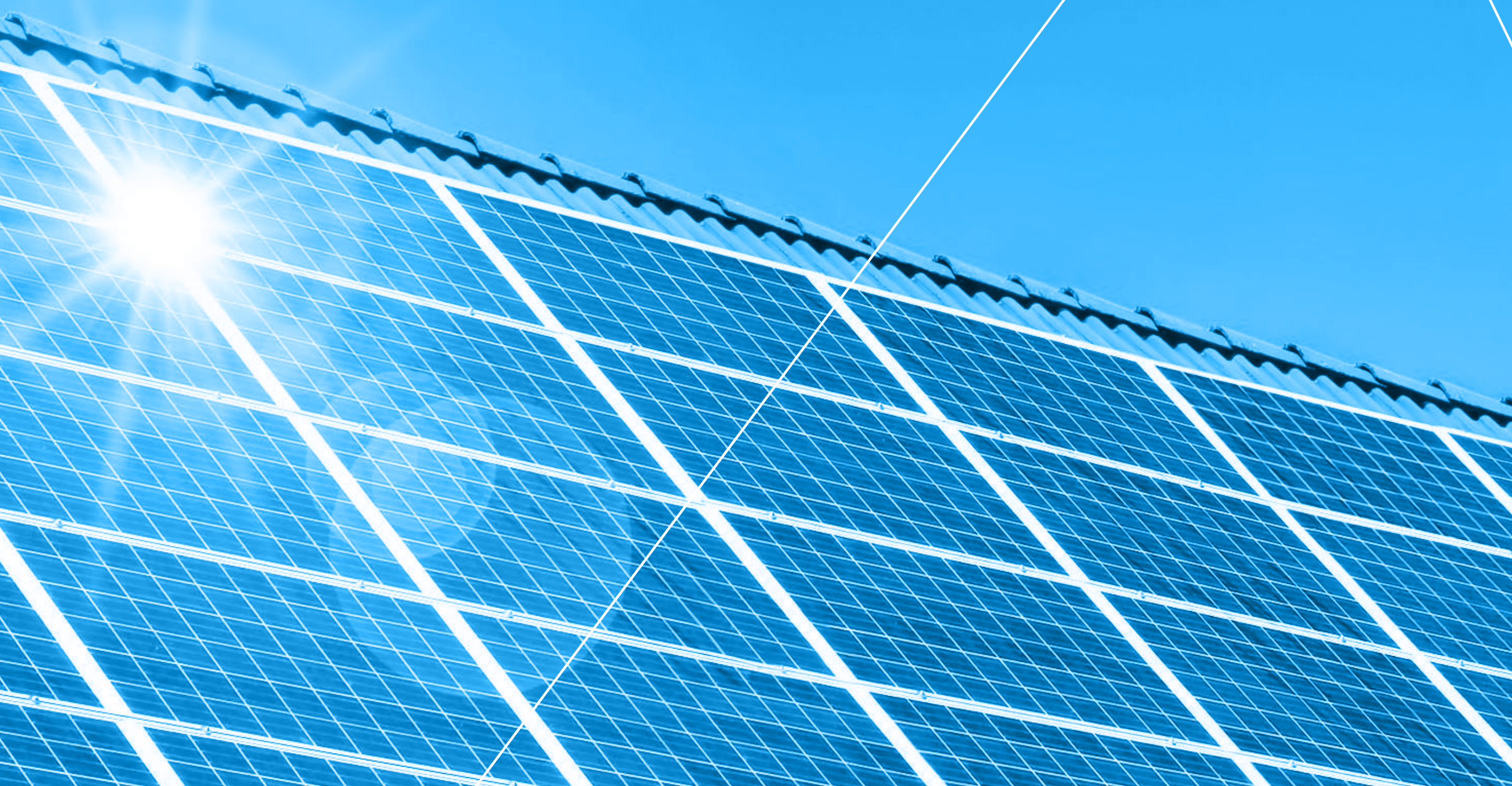
APPENDIX B BASELINE SOLAR IMPACT



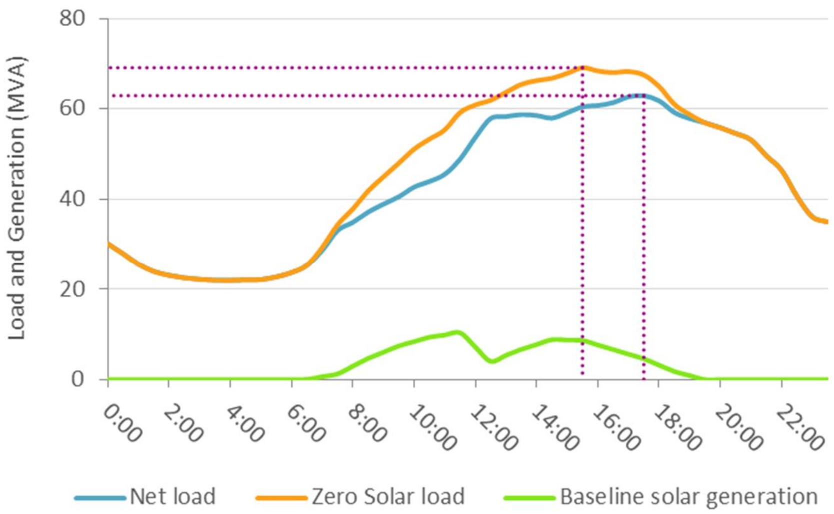
Appendix B Baseline Solar Impact

AECOM has defined the Baseline scenario such that its solar uptake rates match those forecast by AEMO in its National Electricity Forecasting Report 2016 [2]. This results in large amounts of solar PV being installed in the Baseline scenario, which leaves little opportunity for LGNCs to provide value through additional solar PV.

To demonstrate this point, AECOM has measured the peak reduction value provided by all solar, rather than just the additional solar that has been incentivised by the LGNC. That is, a comparison of a “Zero Solar” scenario with the Baseline scenario. Under the Zero Solar scenario there is considered to be no solar PV installed (i.e. existing solar PV is removed and no future solar PV is assumed). The Zero Solar scenario is effectively a “gross demand” profile, before solar generation occurs.

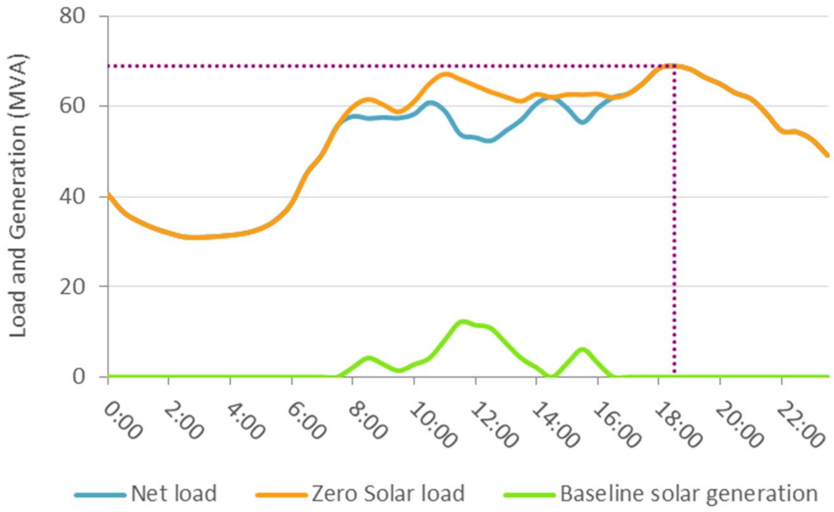
At Belconnen in Data Set 1, the peak period in the Zero Solar scenario occurs at 3:30pm on 19 January. The addition of solar PV in the Baseline scenario reduces peak demand in this period leading to a new peak emerging at 5pm on the same day. This is shown in Figure 75.

Figure 75 Belconnen, Zero Solar scenario compared with Baseline solar peak day 19 January FY33 (Data Set 1)



From FY33 onwards, the Baseline level of solar has reduced the summer peak sufficiently that it is shifted to a winter peak at 6:30pm 17 August. Note that from FY33 onwards, the peak demand reduction shown in Figure 55 is the difference between the Zero Solar peak at 3:30pm 18 January, and the Baseline peak at 6:30pm 17 August. The Baseline peak at 6:30pm 17 August is not being reduced (refer to Figure 76) however this peak increases annually at a slower rate than the zero solar scenario peak at 3:30pm 18 January. Therefore, there is still an increased level of peak demand reduction observed each year from FY33 onwards, although this a consequence of the DPM’s load profile projection algorithm, rather than a direct consequence of installing additional solar PV.

Figure 76 Belconnen, Zero Solar scenario compared with Baseline solar peak day 17 August FY46 (Data Set 1)



A similar pattern of peak reduction is observed for Data Set 2 at Belconnen ZS, however there is no peak reduction observed for Data Set 3 at Belconnen because its peak demand period occurs at 6:30pm 30 June outside of sunlight hours. This information is summarised in Table 43 for all sites.

Table 43 Zero Solar scenario compared with Baseline – Peak reduction observed

	Data Set 1	Data Set 2	Data Set 3
Belconnen	ü	ü	X
Flemington	ü	ü	ü
Emerald	ü	ü	ü
MW Peak Reduction in Augmentation Year	**Data Set 1**	**Data Set 2**	**Data Set 3**
Belconnen (FY19)	2.89 MVA	2.12 MVA	0 MVA
Flemington (FY23)	2.08 MVA	1.83 MVA	1.30 MVA
Emerald (FY33)	0.81 MVA	2.39 MVA	2.05 MVA

These results show that solar PV has the ability to significantly reduce peak demand with large reductions shown at Emerald and Flemington in all three data sets, and large reductions shown at Belconnen for two of the three data sets. However, this impact is not a long term prospect. As additional solar is added, its ability to provide peak reductions diminishes.

This can be observed when comparing the peak reduction values for Belconnen and Emerald under Data Set 1. Given the higher levels of solar PV uptake in Emerald compared with Belconnen, and the fact that the values presented for Emerald ZS are for FY33 compared with FY19 for Belconnen, it is expected that there would be significantly more solar PV installed at Emerald ZS. However, the peak demand reduction value for Emerald is significantly lower than that for Belconnen, at 0.81MVA compared with 2.89 MVA.

This occurs because the new peak at Emerald ZS, which is outside sunshine hours, is only 0.81 MVA lower than the original peak. Therefore the amount of peak reduction possible is capped at 0.81 MVA. The results highlight the limited ability of solar PV to reduce the peak demand, and in particular that the capability of solar PV to reduce demand is heavily dependent on the specific conditions on the peak day.

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