Jemena Electricity Networks (Vic) Ltd

2016-20 Electricity Distribution Price Review Regulatory Proposal

Revocation and substitution submission

Attachment 7-16 Advisian - Demand management options

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WorleyParsons Group

Demand Management Options

An Independent Report for Jemena Electricity Networks

16 December 2015

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Version Control

Revision	Date	Author	Reviewed by	Comments
0	11/12/2015	E. Mudge, P. O'Neil	R. Touzel	Final
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Executive Summary

Jemena has engaged Advisian to provide an external review of its demand management options assessment practices. This report summarises the findings of Advisian's review and considers the outcomes of Jemena's assessment of demand management options for the 2016 to 2020 regulatory control period.

Scope

Advisian's review considers:

a) an assessment of Jemena's procedure for demand management options assessment against its regulatory obligations
b) potential for demand management solutions to avoid or defer network augmentation projects in the 2016 to 2020 period
c) potential for demand management solutions for managing network risk over the 2016 to 2020 period
d) comparison of Jemena's demand management options analysis outcomes against those achieved by other Australian NSPs
e) the review and improvements to the transparency of the quantitative process for evaluating potential non-network options over the 2015 planning cycle.

National Electricity Rules Obligations

As a regulated electricity distribution network, Jemena is required to comply with specific obligations under the National Electricity Rules in relation to the consideration of demand management and other non-network solutions in its network planning and expenditure forecasting. Advisian's review of Jemena's obligations under the NER to consider demand management and other non-network options has found that Jemena has complied with the specific requirements and responded to the regulatory incentives in relation to the:

- publication of its 'Demand Side Engagement Document'
- inclusion of a qualitative summary of its demand management initiatives in the DAPR
- publication of Non-Network Options Reports for RIT-D projects
- focus of the network planning process on selecting the most efficient option
- historical implementation of Demand Management Innovation Allowance projects

Notwithstanding the above, areas have been identified where documentation improvements can be made to Jemena's historical approach to more transparently demonstrate compliance to an external party. These relate to the clearer identification of the reason for not selecting the non-network option in its DAPR and the justification for not proceeding to a non-network options report in cases where Jemena has determined that there is not a credible non-network option. These matters have been addressed in Jemena's demand management options analysis report[1]

Evaluation Process

In 2015 Jemena has undertaken a two stage process to evaluate demand management options to potentially defer capital augmentation projects forecast for 2016 – 2020 and beyond. This is illustrated in Figure 1-1.

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[1] Jemena, *Demand Management for Deferral of Network Augmentation – Options Analysis,* 9 December 2015

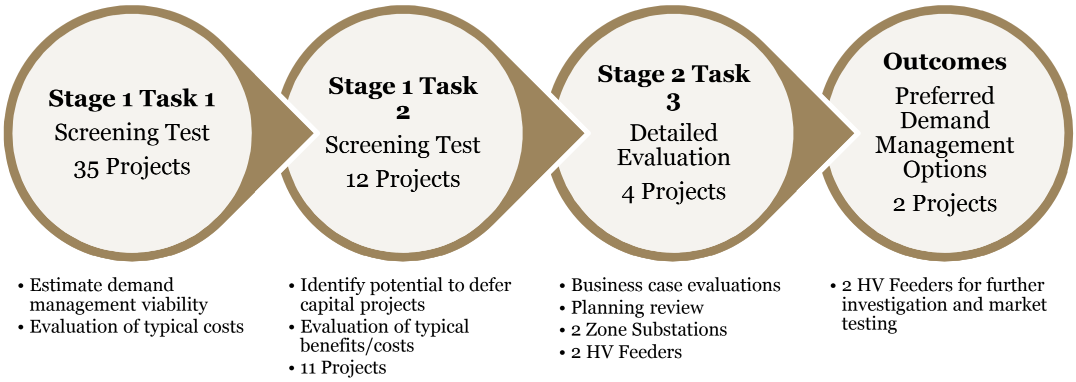

Figure 1-1 Jemena's Demand Management Options Assessment Process

Source: Advisian Summary

Jemena's options analysis report responds directly to the AER's observations regarding the dismissal of non-network options by demonstrating the process, input assumptions, analysis and evaluation of options that are undertaken for Jemena's augmentation capex portfolio. By applying the screening process Jemena found that:

- in all but 11 of the 36 cases, demand management solutions were not a credible alternative for the proposed augmentation expenditure.
- in all but 4 of the 11 cases that passed the initial screening, proceeding with demand management solutions was not found to be reasonable when the project-specific constraints associated with their implementation were taken into account. These constraints were:
  - the demand management option is not able to provide three phase supply, which is a primary driver of the project (two projects);
  - the network area is predominantly residential and it is not realistic to secure significant percentages of reliable, cost effective demand management in the timeframe of the augmentation project (one project);
  - demand management does not offer load transfer capability provided by the augmentation capex project (one project);
  - augmentation capex project may be deferred due to reduced demand growth (one project);
  - a demand response trial is already underway (one project); and
- peak loads come from two major customers and it is not realistic to achieve reliable demand management to meet the requirement from other customers cost effectively within the timeframe of the augmentation project (one project).in 2 of the 4 cases (Sunbury and Flemington), it was established that there was unlikely to be sufficient demand response or energy efficiency opportunities available from large customers to avoid the capacity constraint. However, non-network options reports have been issued for consultation in relation to these projects to test the market for alternative proposals.
- in the remaining 2 cases, (the HV feeders) Demand management options were found to be preferable to the network solution, but their selection as the preferred option remains subject to proving the commercial availability of sufficient demand management capacity on the feeders.

Following the planning review, four proposed capital augmentation projects comprising two zone substation and two HV feeder projects were considered for detailed business case assessment. Of these, Jemena was unable to conclude that a network solution would be preferred for any of the four, and has progressed with publishing a non-network options report for both of the substation augmentations.

Conclusions

Advisian's review of Jemena's approach to evaluating demand management options for the 2016-2020 period has found that:

a) The approach is logical, consistent with the practices of other Australian DNSPs and covers the thirty six augmentation capex projects included in Jemena's expenditure forecast
b) The inputs to the screening evaluation are reasonable, taking into account the large margin for uncertainty that has been applied to this stage of the evaluation to avoid excluding options too early in the process
c) The review of the screening test outcomes against non-capacity factors and project-specific constraints considerations that were not taken into account in the screening assessment is reasonable on the basis that opportunities for demand management are heavily dependent on the location of an emerging capacity constraint.
d) The probabilistic approach to the calculation of expected unserved energy is based on a consistent approach and suitable for providing a comparative assessment of the relative benefits

In comparison to other networks, Advisian found that:

a) Jemena's approach to apply a two stage screening process is similar to the approach adopted by other Australian distribution networks and is designed to avoid eliminating options too early in the process.
b) The limited demand management applications identified through Jemena's demand management options assessments are consistent with the experience of other Australian DNSPs
c) The impact of broad-based demand management and energy efficiency measures, customer response to higher electricity prices and economic factors have, in aggregate, reduced the forecast demand growth rates across most distribution networks, resulting in fewer opportunities for demand management
d) Overall Jemena is actively working to continuously refine its processes to ensure that demand management solutions continue to contribute to managing augmentation expenditure where it is economically preferable to network solutions. This includes providing greater transparency over the reasons for demand management options not proceeding and more active engagement with potential non-network service providers.

Therefore Advisian concludes that Jemena's demand management options assessment approach is comparable to the practices of other Australian distribution networks, with Jemena's historical commitment to demand management noted by the AER[2]. Jemena is clearly focusing on improvements to market engagement and more transparent assessment in relation to the evaluation of non-network options.

In relation to the specific matters that were raised by the AER regarding Jemena's demand management options assessment practices, Advisian concludes that:

a) Jemena has reviewed and improved the transparency of the quantitative process that has been used to evaluate potential non-network options so the reasons for not proceeding with non-network options for augmentation projects are clearly demonstrated.
b) the quantitative assessment conducted during the 2015 planning cycle supported Jemena's initial view that there were limited options beyond those identified in the 2014 DAPR and accepted by the AER as an efficient capex/opex substitution.
c) demand management options do not represent a credible alternative for Flemington or Sunbury zone substations due to the scale of demand management that is required.
d) demand management options do not address the underlying need for the Preston conversion project as the substation is not expected to operate outside its N-1 rating.
e) Jemena has commenced the consultation for non-network options for the Flemington and Sunbury zone substation projects which will test whether the external market can provide an alternative solution prior to commitment to network augmentation.

Advisian considers that Jemena's option analysis document and the associated planning analysis demonstrates that Jemena considers demand management options for all of its major augmentation

[2] AER, *Preliminary Decision Attachment 12 –Demand Management Incentive Scheme,* October 2015, p. 12-9

projects, including documenting the reasons for not proceeding with a non-network option at each stage of the assessment. This view is supported by Jemena's historical commitment to demand management, as recognised by the AER in its commentary on the preliminary DMIS decision.

1 Introduction

Jemena has engaged Advisian to provide an external review of its demand management options assessment practices. This report summarises the findings of Advisian's review and considers the process of Jemena's assessment of demand management options for the 2016 to 2020 regulatory control period.

1.1 Scope of Review

The scope of this engagement has been delivered in two stages. The first stage has involved providing assistance to Jemena staff to further develop and document Jemena's demand management options analysis approaches as part of the 2015 planning cycle.

This report covers the second stage of the engagement. It draws on Advisian's understanding of Jemena's processes that were gained during the first stage to provide an external review of Jemena's demand management options analysis approach covering:

a) an assessment of Jemena's procedure for demand management options assessment against its regulatory obligations
b) potential for demand management solutions to avoid or defer network augmentation projects in the 2016 to 2020 period
c) comparison of Jemena's demand management options analysis outcomes against those achieved by other Australian NSPs
d) the review and improvements to the transparency of the quantitative process for evaluating potential non-network options over the 2015 planning cycle

Notwithstanding Advisian's prior assistance during stage 1, this report has been prepared on an independent basis, and led by separate personnel, to provide Advisian's external assessment of Jemena's demand management option assessment practices and the reasonableness of the outcomes. To achieve this, Advisian has considered Jemena's documentation and additional publicly available information sources to form its own view on the process, application and outcomes of Jemena's consideration of demand management options.

1.2 Background

In a planning and regulatory context, the use of demand management can allow investment in new assets to either be avoided or deferred. This can be achieved through a range of measures that allow the maximum demand to be managed within the existing capacity of the network. Solutions that are typically considered include:

- demand response, representing voluntary and controlled customer load curtailment
- mobile generation, representing the use of mobile generation for network support purposes
- embedded generation, representing contracts for the use of customer emergency generators for network support purposes
- solar PV, representing the cumulative effect of DNSP supported small scale solar PV installations
- energy storage, representing network and customer scale battery storage
- energy efficiency, representing targeted initiatives by the DNSP aimed at energy efficient equipment upgrades

It is important to note that the impact of 'broad based' or 'mass-market' (residential and small commercial) demand management and energy efficiency initiatives is normally reflected as a reduction in the maximum demand growth rate when aggregated to the distribution feeder or zone substation level. Therefore the effect of mass market initiatives is taken into account indirectly through the reduced growth rates that have been applied in the demand forecasts. As a result, this report only considers the discrete demand management options for the deferral and risk management of Jemena's larger scale augmentation projects.

The effect of recent investment in Australian distribution networks has heightened awareness of the potential value of demand management options to reduce the scale of required augmentation capital expenditure (and subsequently, the cost of network services). However, the relatively modest growth rates that are forecast across Jemena's network mean that:

- there are fewer network augmentation projects that are required when compared to historical average growth rates
- the timing for augmentation investment is more sensitive to changes in forecast demand growth rates
- the period for investment deferral arising from demand management solutions is likely to be longer

Therefore whilst there are likely to be fewer opportunities for demand management solutions (due to the reduced overall need for major augmentation), the potential deferral benefits are likely to extend for a longer period such that there is a larger benefits stream arising from avoided investment. In this environment, there is also a greater opportunity for demand management to manage risks arising from demand forecast uncertainty in the near term. Consequently, it is increasingly important for distribution networks to demonstrate how they have considered demand management options in their decision-making process.

For this reason, Jemena has revisited analysis of the demand management options that could be applied to its augmentation capex projects for the 2016-2020 period, to provide greater transparency over the process and clarify the rational for not proceeding with potential non-network options. This analysis reconsidered Jemena's prior positions in further detail as part of its preparation of augmentation capex forecasts for the 2016-20 period. The approach and outcomes are summarised in the report D*emand Management for Deferral of Network Augmentation*[3].

1.3 Report Structure

The remainder of this report is structured to reflect the key aspects of Advisian's review as follows:

- **Section 2** summarises Jemena's obligations to consider demand management and other non-network options and the compliance approaches taken by other Australian DNSPs

- **Section 3** outlines Jemena's current approach to the consideration of demand management options and provides Advisian's review of the approach and outcomes of the process.

- **Section 4** considers the issues raised in the AER Preliminary Determination in relation to Jemena's consideration of demand management options, describes the additional analysis completed under Jemena's more detailed approach and provides Advisian's assessment of the augmentation capex associated with the affected projects.

- **Section 5** summarises Advisian's conclusions in relation to Jemena's obligations, approach and analysis of demand management options, including suggestion of any areas for further refinement.

The report concludes that Advisian considers Jemena's planning analysis and option analysis document demonstrate the consideration of demand management options for all of its major

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[3] Jemena, *Demand Management for Deferral of Network Augmentation – Options Analysis,* 9 December 2015

augmentation projects, and the reasons for not proceeding with a non-network option at each stage of the assessment are documented.

2 Demand Management Option Analysis Obligations

This section summarises Jemena's obligations to consider demand management and other non-network options as part of its network planning and expenditure forecasting.

2.1 NER Requirements

As a regulated electricity distribution network, Jemena is required to comply with specific obligations under the National Electricity Rules in relation to the consideration of demand management and other non-network solutions in its network planning and expenditure forecasting.

The NER requires Jemena to document its engagement strategy, engage with demand side stakeholders, demonstrate how demand management and non-network options have been considered in the planning process and consult on potential non-network solutions

The specific obligations relate to:

- the requirement for demand side engagement
- the treatment of demand management and non-network solutions in the augmentation planning process,
- the review and public consultation as part of the RIT-D approvals process
- the overarching obligations for efficient investment in the network.

Each of these points are described more fully in the following sections.

2.1.1 Demand Side Engagement Obligations

Jemena is required to satisfy the specific demand side engagement obligations relating to its demand side engagement strategy and publish a 'demand side engagement document' in accordance with NER 5.13.1 (e) to (j).

"5.13.1 Distribution annual planning review…

…Demand side engagement obligations

(e) Each Distribution Network Service Provider must develop a strategy for:

(1) engaging with non-network providers; and

(2) considering non-network options.

(f) A Distribution Network Service Provider must engage with non-network providers and consider non-network options for addressing system limitations in accordance with its demand side engagement strategy.

(g) A Distribution Network Service Provider must document its demand side engagement strategy in a demand side engagement document which must be published by no later than 31 August 2013.

(h) A Distribution Network Service Provider must include the information specified in schedule 5.9 in its demand side engagement document.

(i) A Distribution Network Service Provider must review and publish a revised demand side engagement document at least once every three years."

Jemena released its original document in August 2013 and published the current Demand Side Engagement Document[4] in March 2014, which addresses the specific requirements detailed in Schedule 5.9 of the rules. Along with the supporting measures to engage more closely with non-network providers, Jemena has demonstrated compliance with its specific obligations in relation to the demand side engagement obligations.

2.1.2 Annual Planning Review Obligations

Under NER 5.13.2, Jemena is also required to publish a Distribution Annual Planning Report (DAPR) that sets out the results of the annual planning review for the forward planning period. The DAPR must contain certain information in relation to demand management and non-network options as follows:

"(l) information on the Distribution Network Service Provider's demand management activities, including:

(1) a qualitative summary of:

(i) non-network options that have been considered in the past year, including generation from embedded generating units;

(ii) key issues arising from applications to connect embedded generating units received in the past year;

(iii) actions taken to promote non-network proposals in the preceding year, including generation from embedded generating units; and

(iv) the Distribution Network Service Provider's plans for demand management and generation from embedded generating units over the forward planning period"[5]

Jemena's 2014 DAPR was published in December 2014 and amended in April 2015 to incorporate certain corrections to cost estimates and network limitations.[6] Section 5.3 of the 2014 DAPR describes Jemena's approach to Demand Management and notes the specific demand management activities that commenced in the year[7]. The volume of known embedded generation is also reported for each substation in section 5.4 and each sub transmission line in Section 5.5. The potential for demand management options is reviewed during each planning cycle to take into account changes in demand forecast, customer loads and available technology.

Cases where embedded generation and demand management were considered as an option are also identified, with demand response solutions selected as the preferred option for Footscray East Zone

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[4] Jemena, *Demand Side Engagement Document Jemena PL0140,*March 2014,

[5] NER, Schedule 5.8

[6] Jemena, *Distribution Annual Planning Report 2014*, April 2015 (At the time of drafting, Jemena had not published it's 2015 DAPR)

[7] ibid, Section 5.3.2 p.38.

Substation[8] and for the North Heidelberg sub transmission loop limitation from the Thomastown Terminal Station.[9] In the Preliminary Decision, the AER accepted Jemena's proposed demand management approach for these constraints as an efficient capex-opex substitution[10].

Therefore Jemena has complied with the specific planning obligations in relation to the identification of demand management options and other non-network solutions for network constraints. However Advisian notes that in most cases, the DAPR does not specifically identify the reason for rejecting potential non-network solutions. These reasons are documented in the 'Demand Management for Deferral or Network Augmentation Options Analysis' document and in the Non-Network Options reports for projects progressing through the RIT-D process.

2.1.3 RIT-D Obligations

Clause 5.17.3 of the NER requires Jemena to apply the AER's Regulatory Investment Test for Distribution (RIT-D)[11] to regulated augmentation capex projects over $5m[12]. The RIT-D obligations commenced from 1 January 2014, however consultation requirements for non-network solutions have existed prior to the RIT-D.

As part of the RIT-D process, Jemena is required to identify the need for investment and develop a set of credible network and non-network options. The costs and benefits associated with each credible option must be assessed and then ranked based on the net economic benefits.

Where non-network options are identified as a significant part of a credible option the RIT-D process then requires Jemena to publish a 'non-network options report'[13] and provide stakeholders with at least three months to make submissions. Following the receipt of submissions Jemena is required to publish a draft and final 'project assessment report' within certain timeframes[14].

Where Jemena determines on reasonable grounds that a non-network option will not represent a potential credible option, a 'non-network options report' is not required to be published under the RIT-D process[15]. This allows for an initial screening of augmentation projects to ensure that non-network options consultations are not required in cases where non-network solutions don't represent a credible alternative. In these cases, Jemena is required to "*…publish a notice setting out the reasons for its determination, including any methodologies and assumptions it used in making its determination"*[16]

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[8] ibid, p. 78

[9] ibid, p. 149

[10] AER, *Preliminary Decision Attachment 7- Operating Expenditure,* October 2015, pp. 7-76 to 7-77

[11] AER, *Regulatory Investment Test for Distribution*, August 2013

[12] Subject to the specific exclusions noted in NER 5.17.3

[13] *The requirements for the 'non network options report' are specified in NER 5.17.4(e)*

[14] AER, *Regulatory Investment Test for Distribution Application Guidelines*, August 2013, p. 14

[15] *NER 5.17.4(c)*

[16] *NER 5.17.4(d)*

Jemena's 2014 DAPR notes that it did not complete or progress any RIT-D assessments during 2014[17]. Therefore no associated non-network options reports have been published. As part of the 2015 planning cycle, Jemena published Non-Network Options Reports for the following projects in October 2015:

- Flemington Electricity Supply
- Sunbury – Diggers Rest Electricity Supply

Therefore, Jemena has demonstrated compliance with its specific obligations for considering and consulting on non-network options under RIT-D.

2.1.4 Expenditure Forecasting and Efficient Investment Obligations

In addition to the specific obligations with regard to network planning and RIT-D, Jemena has a general obligation to ensure that its expenditure is efficient. This is reflected in the capital expenditure criteria[18] that form the basis for the AER's assessment of capex forecasts and ultimately, the National Electricity Objective's focus on efficient investment.

Given Jemena's compliance with its specific non-network and demand management obligations, it is the broader driver for the efficient investment that leads Jemena to consider demand management options in more detail. This is because the market for external non-network proponents is relatively immature, with limited viable solutions identified during historical consultations.

During the 2015 planning cycle, Jemena has reviewed its demand management options assessment process to more clearly document its consideration of potential non-network options for augmentation capex projects. This is discussed in section 3.

2.1.5 Demand Management Incentive Scheme

Jemena has historically accessed funding within its Demand Management Innovation Allowance (DMIA) under the AER's Demand Management Incentive Scheme (DMIS). The scheme is designed to provide incentives for DNSPs to implement efficient non-network alternatives, or otherwise manage expected demand. Projects can involve direct demand management initiatives or otherwise support enabling investment and capability development in relation to demand management.

In the Preliminary Decision, the AER recognised Jemena's historical commitment to demand management in relation to the evaluation of Jemena's proposed increase to the DMIA. The AER did not accept the proposed increase due to the upcoming revisions to the DMIS but stated:

> *"…Whilst Jemena have shown their commitment to demand management through the projects implemented in the 2011-15 regulatory period we do not consider additional funding is appropriate at this stage…"*[19]

On this basis, it is apparent that Jemena has been actively responding to the demand management incentives under the DMIS. This is supported by the AER's most recently published Assessment

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[17] Jemena, *Distribution Annual Planning Report 2014*, April 2015, p.5

[18] NER 6.5.7

[19] AER, *Preliminary Decision Attachment 12 –Demand Management Incentive Scheme,* October 2015, p. 12-9

Report[20] which identifies that Jemena spent approximately 71% of its approved DMIA in the first three years of the five year period covered by the scheme.

2.2 Conclusions

Advisian's review of Jemena's obligations under the NER to consider demand management and other non-network options has found that Jemena has complied with the specific requirements and responded to the regulatory incentives in relation to the:

a) publication of its 'Demand Side Engagement Document'
b) inclusion of a qualitative summary of its demand management initiatives in the DAPR
c) publication of Non-Network Options Reports for RIT-D projects
d) focus of the network planning process on selecting the most efficient option
e) historical implementation of Demand Management Innovation Allowance projects

Notwithstanding the above, areas have been identified where documentation improvements can be made to Jemena's historical approach to more transparently demonstrate compliance to an external party. These relate to the clearer identification of the reason for not selecting the non-network option in its DAPR and the justification for not proceeding to a non-network options report in cases where Jemena has determined that there is not a credible non-network option. These matters have been addressed in Jemena's demand management options analysis report[21]

[20] AER, Demand Management Innovation Allowance Assessment 2012-13 and 2013, April 2015, p. 8.

[21] Jemena, *Demand Management for Deferral of Network Augmentation – Options Analysis,* 9 December 2015

3 Jemena's Approach to Demand Management Options Assessment

This section details how Jemena has considered demand management options in its planning and expenditure forecasting and provides Advisian's conclusions in relation to each step of the process.

3.1 Process Overview

In 2015 Jemena has undertaken a two stage process to evaluate demand management options to potentially defer capital augmentation projects forecast for 2016 – 2020 and beyond.

The first stage involves the application of a high level screening process to identify the projects where a demand management option could represent an economically preferable alternative to network augmentation.

The second stage applies a detailed evaluation to the projects that proceed through the screening test, including consideration of the technical feasibility of the solution to address the network needs. This is illustrated in Figure 3-1.

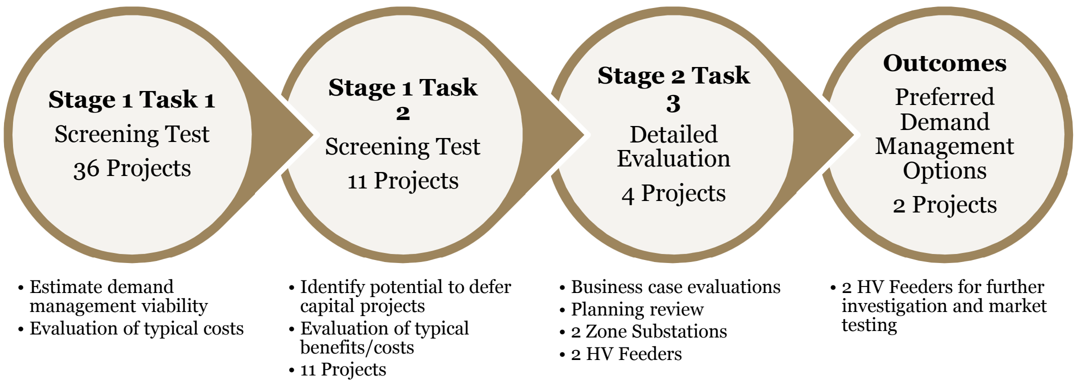

Figure 3-1 Jemena's Demand Management Options Assessment Process

Source: Advisian Summary

3.2 Demand Management Options Considered

Jemena considers a range of demand management options in its planning process to evaluate the potential for non-network alternatives. For the purpose of its screening test, the following six options are evaluated:

- demand response – reduction in demand by customers on receipt of a signal;
- mobile generation (diesel) – Jemena installs generators to reduce demand on the network asset;
- embedded generation – customer owned cogeneration or emergency generators put into operation on receipt of a signal;
- energy storage (batteries) – Jemena or service provider installs battery banks to reduce demand on the network asset;

- solar photovoltaics (PV) – Jemena subsidises PV installations on industrial or commercial facilities providing generation to reduce demand on the asset during peak periods; and
- energy efficiency – Jemena subsidises energy efficiency projects to reduce demand on the asset throughout the year;

Advisian notes that the six options are not an exhaustive list of potential non-network solutions, however they do represent the most likely sources of large scale demand management options for the larger augmentation projects that are the focus of this report, as well as the RIT-D process. Domestic solar PV, energy efficiency and other broad based demand management measures have not been included in the assessment on the basis that the projected uptake of these technologies is included in the demand forecast.

Jemena undertakes power factor correction through the installation of capacitors on the network. Therefore, power factor correction on customer sites is likely to be driven by reactive power charges driving medium to long term improvement rather than the requirement for short term demand management. On this basis power factor correction on customer sites is unlikely to provide the scale of demand management that is required.

Other measures such as thermal energy storage or fuel switching are dependent on the availability of large cooling loads and the ability to install significant alternative plant such as chilled water storage facilities. These opportunities require significant investment by the customer and have typically been limited to applications such as universities and hospitals. The limited application and uncertain implementation costs associated with these types of initiatives mean that it is reasonable to exclude these from the assessment.

Therefore, Advisian considers that the demand management options included in the assessment are reasonable and represent the most likely options to be cost effective on the Jemena network. The approach to include a wide range of demand management options in the analysis to identify areas of interest is appropriate given the high level screening nature of the assessment and application across all of Jemena's proposed augmentation expenditure projects.

3.3 Stage 1 Screening Test

Jemena's stage 1 process involves two tasks:

1) This identification of the typical demand management options and development of a consistent basis for evaluating the likely costs associated with the potential solution; and,
2) The application of the screening test to the augmentation capex portfolio.

In task 1, the thirty six augmentation capex projects proposed for the 2016-2020 regulatory period were assessed on a consistent basis to shortlist projects where demand management could potentially provide a cost effective alternative. Overall, the thirty six augmentation projects were screened down to eleven through this process.

3.3.1 Task 1 – Estimate Demand Management Viability

For the purpose of assessing the relative costs and benefits arising from different demand management options, Jemena has developed a consistent set of cost assumptions. These are applied to the benefits that are derived from Jemena's standard load/energy at risk calculations for each project in the year 2020.

Whilst the options are ultimately required to meet the load and energy at risk in each year rather than the 2020 estimates that have been used in the analysis, the use of 2020 estimates is likely to represent a 'worst case' in an environment of rising or steady demand which may inadvertently disadvantage demand management options. The inclusion of significant margin in the comparison of costs and benefits compensates for this bias to ensure that the screening test results only exclude projects that are highly unlikely to have a viable non-network solution.

Similarly in relation to load transfers, Advisian notes that Jemena's network is relatively compact and interconnected when compared to other distribution networks, which results in greater opportunities to manage short term risk through load transfers. The Jemena analysis does not take into account load transfers when calculating load and energy at risk under system normal and N-1 conditions. This is because transferring load can have the effect of moving risk from one area to another and load transfers between HV feeders and zone substations are not considered a long term solution to network constraints. This approach needs to be combined with a continuous assessment of risk and constraints and consideration of feeder reconfiguration to permanently transfer load if it is the most effective option long term.

Jemena has not undertaken a market based tender process to establish the cost estimates for the demand management options considered in this assessment but has relied on data from previous project experience and information in the public domain. Advisian has conducted a high level test of a sample of Jemena's cost inputs as follows:

- The pricing basis for battery storage has been tested with an equipment provider and Jemena's estimates found to be within a reasonable range of the provider's estimates.
- Similarly, the pricing basis for mobile generation used for the screening analysis has been compared with supplier budget pricing for an equipment rental contract mechanism. This is covered in further detail in Section 3.4.1.

In the context of rapidly changing pricing for energy storage and the site specific nature of most energy efficiency and demand response options, the approach taken by Jemena is a practical one.

Section 2 of Jemena's options analysis report[22] provides transparency over the assumptions used for screening purposes. Whilst some assumptions could be subject to challenge or further refinement[23], Advisian recognises that developing more specific estimates of demand management option costs for this level of assessment is likely to add to cost and take considerable time and effort without improving the accuracy of the overall screening process to any significant degree (due to the wide margin applied to screening the results).

3.3.2 Task 2 – Identify Potential to Defer Capital Projects

The second task in stage 1 is to establish the value of the augmentation capex projects when they are deferred out of the regulatory period. This has been calculated by Jemena based on the forecast capex, the regulatory WACC and the number of years of deferral.

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[22] ibid, pp. 3-8

[23] For example, the assumptions regarding the life for mobile generators, fuel costs, management and set up costs for demand response schemes, limited allowances evident for any necessary site acquisition and environmental approvals.

The total value for deferral beyond 2020 is compared to the cost of each demand management option, and, if the cost of the demand management option is within a margin of two times the value of the project deferral, the project was shortlisted for further consideration.

Jemena's application of a factor of two to the demand management benefits recognises uncertainties in the estimating of demand management option costs as described under task 1.

Advisian considers that Jemena's approach to estimating the deferral value of the augmentation projects provides an acceptable approximation for the screening stage of the assessment. The application of a factor to recognise the uncertainty in demand management costs and deferral value minimises the risk of excluding potentially viable demand management options. In practice, this is likely to be a conservative approach resulting in a greater number of options proceeding to a more detailed evaluation.

In total, the application of the stage 1 screening test resulted in eleven augmentation capex projects that were identified as having potential for a demand management solution. These are shown in Table 3-1

Table 3-1 – Network Augmentation Projects with Demand Management Potential ($k 2015)

Project Code	Project Name	Completion Date	Capital Cost	Deferral value	demand management Option Cost	demand management Type
A43	Reconfigure Feeder – ES 23	Nov-2016	2,324	725	1,254	DR
A23	Augment steel section – SBY-14	Nov-2017	1,540	385	145	Batt
A44	New feeder - FT	Nov-2017	1,438	359	207	DR
A45	New feeder – HB-21	Nov-2017	2,457	613	580	Batt
A63	Reconfigure feeders BD-13	Nov-2017	1,482	370	605	DR
A24	Augment steel section – SBY-32	Nov-2018	1,189	223	73	Batt
A47	New feeder – NH-19	Nov-2019	1,232	154	195	DR
A89	Redevelopment Sunbury Zone Substation - SBY	Nov-2018	12,645	2,367	4,608	E Eff
A103	Redevelop Fairfield Zone Substation - FF	Nov-2018	8,820	1,651	1,544	E Eff
A74	FT Zone Substation Capacity	Nov-2017	10,426	2,602	4,393	E Eff
A35	Establish tie-line between SBY-32 and SBY-11	Nov-2017	1,254	313	290	Batt

Source: Jemena[24]

3.4 Stage 2 Detailed Evaluation

This section considers the Stage 2 evaluations that have been completed and incorporated into the expenditure forecast. To ensure that the assessment takes the current forecast into account, Jemena has re-assessed the shortlisted projects to reflect the spatial demand forecasts that were updated in October 2015.

3.4.1 Task 3 – Business Case Evaluation

The eleven demand management opportunities identified as having potential to be cost effective to defer augmentation projects were reviewed by Jemena's Capacity Planning and Assessment team to confirm whether demand management could offer similar benefits to the proposed augmentation project.

This included consideration of non-capacity factors and practical limitations for implementation that were not taken into account in the screening test as detailed in Table 3-2 of Jemena's report[25]. In these cases, proceeding with demand management solutions was not found to be reasonable when the project-specific constraints associated with their implementation were taken into account. Through removal of projects where demand management cannot provide the key non-capacity benefits, Jemena has reduced the number of projects where demand management could potentially defer the augmentation capex from eleven to four.

The reasons for eliminating the seven projects are as follows:

- The demand management option is not able to provide three phase supply, a primary driver of the project (two projects);
- The network area is predominantly residential and it is not realistic to secure significant percentages of reliable, cost effective demand management in the timeframe of the augmentation project (one project);
- demand management does not offer load transfer capability provided by the augmentation capex project (one project);
- augmentation capex project may be deferred due to reduced demand growth (one project);
- A Demand Response (DR) trial is already underway (one project); and
- Peak loads come from two major customers and other customers are residential. In this environment the probability of securing the required scale of reliable, cost effective demand management in the timeframe of the augmentation project is low. When this is taken into account, it is prudent to include the network solution in the expenditure forecast.[26] (one project).

Following the planning review, the following four proposed capital augmentation projects were considered for detailed business case assessment.

- redevelopment of Sunbury (SBY) zone substation
- Flemington (FT) zone substation capacity upgrade

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[24] ibid p. 11

[25] ibid

[26] In relation to the uncertainty associated with the ability to secure firm demand management, Advisian notes that should a customer driven non-network option subsequently arise, the avoided investment benefits in the current period would ultimately be shared with customers through the capex incentive scheme. The long term avoided investment benefits would also be passed on to customers through the lower RAB and associated return on/of assets in future regulatory periods.

- ES-23 feeder reconfiguration
- new HB-21 feeder

For each project, the following demand management options were evaluated along with a ‘do nothing’ option and the proposed augmentation:

- demand response;
- energy efficiency;
- mobile generation; and
- battery storage.

Solar PV and embedded generation options were not assessed for these projects due to the high cost that was assessed at the screening test stage and the limited existing customer generation that is available in the areas of interest.

For the Essendon HV feeder and Heidelberg HV feeder projects, a do nothing option was not a reasonable solution so the demand management options were compared to the augmentation project.

The 2015 spatial demand forecasts were used as the basis for future demand, with load and energy at risk estimates for zone substations calculated using probabilistic methods. Load at risk estimates during single outage conditions were applied for HV feeders.

Advisian notes that the timeframe used in Jemena’s evaluation means that the total benefits calculated for the options are large in comparison to the cost of the proposed projects. This is simply because the analysis assumes that no other action will be taken in the future such that the cost of expected unserved energy will continue to accrue for the duration of the assessment. Whilst this is unlikely to occur in practice, the common treatment across each option allows a meaningful comparison to be made on the basis of the difference in net benefits for each option.

Advisian considers that the use of probabilistic load and energy at risk assessment for the zone substations and a deterministic analysis for the HV feeder demand is reasonable. This reflects a suitable level of assessment for feeder assets, in line with the lower capital cost involved and the complex nature of potential load transfers at feeder level. Similarly, the use of the proposed augmentation capex project as the alternative option for feeder projects is considered to be reasonable on the basis that the network augmentation has already been justified by the load at risk.

As noted in section 3.3.1, Advisian has also reviewed the cost basis for mobile generation using budget pricing information provided by a mobile generator services provider. The costs in Table 3-2 show that the figures used by Jemena for the detailed assessment are lower than the typical cost of generator hire. One of the key assumptions in the Advisian analysis is that the generators are available six months of the year to cover summer and winter peaks, but not required in the spring and autumn shoulder seasons.

Table 3-2 Mobile Generation Cost Comparison

Project Code	Project Name	Period of assessment	Jemena total cost ($,000)	Advisian total cost ($,000)	% difference
A43	Reconfigure Feeder - ES23	2016 - 2022	$2,457	$9,375	280%
A45	New feeder - HB21	2016 - 2022	$4,583	$5,625	23%
A89	Redevelopment Sunbury Zone Substation - SBY	2016 - 2024	$46,884	$79,594	70%

Project Code	Project Name	Period of assessment	Jemena total cost ($,000)	Advisian total cost ($,000)	% difference
A74	FT Zone Substation Capacity	2016 - 2024	$39,394	$124,121	295%

On a contract hire basis, mobile generation employed on a longer term contract could be up to three times more expensive than Jemena's estimates, reducing the attractiveness this DM option even further than Jemena has suggested.

3.5 Outcomes

Jemena's demand management options assessment process has shortlisted eleven projects for detailed evaluation. After review of the ability of demand management to provide similar benefits to the capital augmentation projects, four opportunities were evaluated using the cost benefit methodology described in section 3.4.1. Of these, Jemena was unable to conclude that a network solution would be preferred for any of the four and has progressed with publishing a non-network options report for both of the substation augmentations. The potential for demand management solutions for feeder projects will be evaluated as part of Jemena's normal planning processes with the most efficient option proceeding at the time of investment commitment.

Sunbury and Flemington Zone Substations

In the cases of the Sunbury and Flemington zone substation augmentation capex projects, the net benefits of the network augmentation option are close to the Demand Response (Sunbury) or Energy Efficiency (Flemington) options. However, as the load and energy at risk in each case represents a substantial proportion of the total demand on the substations, it would be necessary to secure a very large amount of demand management. In both cases, the total requirements exceed the level of energy efficiency or demand management that could reasonably be secured by 2021.

For the demand response option to be feasible for Sunbury, at least 25 MVA of demand response or energy efficiency would be required by 2021. This equates to more than twice the demand attributable to the largest 24 customers. Similarly, Flemington requires approximately 22MVA of demand response or energy efficiency by 2021, but the largest 11 customers only consume 14 MVA of demand in total.

Given the number of individual customers that Jemena would need to reach agreements with to achieve the required volumes, Advisian considers that an economically preferable, technically viable demand management solution is unlikely to represent a credible option.

Essendon and Heidelberg HV feeder projects

The evaluation of the two HV feeder projects found that demand response had the highest net benefits, with the network augmentation option representing a comparable option. In these cases, the solution is reliant on securing sufficient demand response or energy efficiency measures in largely residential areas.

Therefore Advisian agrees that it is prudent for Jemena to subject these projects to further investigation and market testing to confirm the combination of demand management options that may be practical to defer these projects. These options will be considered along with any change in the demand forecast prior to investment commitment.

3.6 Comparison with other NEM DNSPs

This section provides a high level comparison of the process of Jemena's consideration of Demand Management Options against other NEM DNSPs based on publicly available documentation from the network planning and regulatory processes. The approaches that are taken to consider demand management options, along with the main outcomes are considered below.

3.6.1 Demand Management Approach

Including Jemena, the demand management approaches of 10 of the 13 NEM DNSPs[27] have been reviewed at a high level to provide an assessment of the approach, extent and type of demand management initiatives that have been pursued across Australian distribution networks. This involved the review of the main publicly reported information on each DNSP's demand management activities from the demand management engagement strategy documents, annual planning reports, network performance reports and company websites.

Advisian's review found that other Australian distribution networks apply similar processes to Jemena[28] with other networks identifying limited applications for specific non-network solutions.

For example, Ausgrid identified six potential opportunities from a total of 51 projects (11.7%) which is in proportion to Jemena's identification of four potential opportunities from a total of 36 projects (11.1%). Ausgrid summarises the outcomes of its demand management assessments as follows:

> *"Ausgrid did not complete any full investigations into demand management options for specific network needs in 2013/14. However during 2013/14 a comprehensive review of all projects in the 28 Sub transmission Area Plans was carried out for the planning period to 2024/25. 51 planned projects met the criteria for consideration of demand management options. Of these, six potential opportunities were identified. The capital deferrals enabled by the use of non-network options at these locations has been built into Ausgrid's capital work plan. These demand management opportunities will be fully investigated, including public consultation, at a later date in the network planning cycle."*[29]

South Australia Power Networks (among others) applies a similar screening process to Jemena with a focus on specific demand management technologies. SA Power Networks describe a framework for the assessment of potential non-network options against a range of typical applications. The approach is based on the assessment of the indicative cost per KVA and the value of avoided or deferred investment and summarised as follows:

> *"The framework is comprised of all technically and commercially demonstrated non-network solutions that could be applied by SA Power Networks, as well as an indicative cost per kVA, potential level of kVA reduction and timeframes for implementation. Typical approaches used*

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[27] *The sample covered DNSPs in ACT (ActewAGL), NSW (Ausgrid, Endeavour Energy, Essential Energy), Queensland (Ergon Energy, Energex), South Australia (SA Power Networks) and Victoria (CitiPower/Powercor and Jemena).*

[28] For Example: Ausgrid, *Electricity Network Performance Report 2014,* November 2014, p.13, South Australian Power Networks, *Demand Side Engagement Document*, Version 1, p. 22,

[29] Ausgrid, *Electricity Network Performance Report 2014,* November 2014, p.14

to provide cost effective non-network alternatives to the augmentation of the distribution network include, but are not limited to, the following:

- *Technologies that improve efficiency at the point of consumption or reduce peak period consumption on a temporary or permanent basis:*
  - *Commercial lighting upgrades*
  - *Customer Power Factor Correction (PFC)*
  - *Voluntary Load Curtailment (VLC)*
  - *Direct Load Control (DLC)*

- *Technologies that provide an alternative source of energy:*
  - *Embedded Generation (existing and new)*
  - *Energy Storage (e.g. Battery)*
  - *Thermal Energy Storage (e.g. Ice Banks)"*[30]

Energex also describes a similar approach to Jemena where broad based demand management activities are taken into account through the underlying demand forecasts. Like Jemena, larger scale demand management options targeted on larger commercial and industrial customers.

> *"Energex has incorporated demand management initiatives into the summer and winter substation forecasts. The initiatives include broad application of air-conditioning control, pool pump control and hot water control capability. Demand management is also being targeted at substations with capacity limitations in an effort to defer capital expenditure. The approach used is to target commercial and industrial customers with incentives to reduce peak demand through efficiency and power factor improvements. The resulting reductions are captured in the Energex Substation Investment Forecasting tool (SIFT) and in the 10 year peak demand forecasts."*[31]

Overall, the approaches taken by Jemena to evaluate and incorporate demand management into its augmentation forecasts are comparable to other Australian distribution networks. This reflects the historical requirements to consider non-network solutions under the NER.

The general approach taken by the distribution networks is similar, with most networks:

- acknowledging the potential for demand management to avoid network augmentation,
- distinguishing between 'broad based' (e.g. tariff, energy efficiency) initiatives and individual project initiatives
- focusing on improving engagement with non-network providers and internal demand management capability
- applying a screening test to identify the specific augmentation project initiatives where demand management offers a reasonable option prior to issuing a non-networks option report.
- identifying modest volumes of expenditure and number of direct applications of demand management, taking into account the scale of the networks.

It is clear that all distribution networks have been refining their approaches to the evaluation and consultation for non-network solutions. In most cases only a small number of specific demand management opportunities can be identified to address major network augmentation constraints. Notwithstanding the small number of large scale non-network solutions that have typically been identified, the distribution businesses are also pursuing broad based demand management initiatives such as energy efficiency, residential solar PV, tariff structure and various direct load control

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[30] South Australian Power Networks*, Demand Side Engagement Document*, Version 1, p. 22

[31] Energex, *Distribution annual Planning Report 2015/16 – 2019/20 Volume 1*, August 2015, pp.54-55

initiatives. These are indirectly reflected in augmentation expenditure via a reduced demand forecast, which captures the demand management benefits in aggregate. Due to the focus of this report on major augmentation projects, the impact of broad-based demand management initiatives on the demand forecast is taken to have been included in Jemena's underlying forecasts.

3.6.2 Demand Management Outcomes

The relatively small volume of individual project based demand management initiatives that have been identified in the DNSPs' annual planning reports reflect, in part, the reduced volume of overall augmentation expenditure due to the recent moderation of demand across the NEM. For example, Essential Energy notes that:

> *"Several factors including global financial conditions, electricity price rises, energy efficiency initiatives and increasing penetration of roof top photovoltaics have contributed to a general downturn in network demand levels and growth rates from about 2010/11. A review of uncommitted major network augmentation proposals was conducted and in most cases the revised timing for the constraint has deferred the need for the augmentation. As a result there were no demand management investigations for major network augmentations undertaken in 2012/13 and this was the case again in 2013/14."*[32]

Regardless of the specific causes for subdued demand, the relatively low demand growth forecast across most NEM distribution networks means that previously forecast augmentation expenditure has already been deferred in preparing forward expenditure plans. As a result, much of the potential for 'avoided investment' benefits form demand management activities are already captured in the expenditure forecasts. The remaining augmentation requirements are typically more localised in areas of new development or redevelopment, with limited opportunity for demand management solutions due to:

- configuration of the existing network for example there are more opportunities for interconnection in more urban networks
- greater availability of customer emergency generators for aggregation in CBD and major commercial areas
- type of customers connected at that point in the network as large industrial and commercial customers provide the greatest opportunity for contracted load control and energy efficiency initiatives
- suitability of a site and associated costs for network supplied embedded generation
- maturity of local demand management markets and the presence of credible non-network service providers

As a result it should be expected that predominately suburban networks (such as Jemena) will generally benefit from factors such as the availability of load transfers, network reconfiguration and the comparatively low cost of interconnection between feeders to manage risk. These factors will typically limit the cost of the network options that are available to Jemena. In turn, the lower cost for network solutions will naturally reduce the volume of viable demand management initiatives when compared to more dispersed networks.

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[32] Essential Energy, *Electricity Network Performance Report 2013/14*, p.17

3.7 Conclusions

Advisian's review of Jemena's approach to evaluating demand management options for the 2016-2020 period has found that:

a) The approach is logical, consistent with the practices of other Australian DNSPs and covers the thirty five augmentation capex projects included in Jemena's expenditure forecast
b) The inputs to the screening evaluation are reasonable for the purpose of a high level assessment, taking into account the wide margin for uncertainty that has been applied to the results to avoid excluding potential options at too early a stage
c) The review of the screening test outcomes against additional factors and practical considerations that were not specifically taken into account in the screening assessment is reasonable on the basis that opportunities for demand management are heavily dependent on the location of an emerging capacity constraint.
d) The probabilistic approach to the calculation expected unserved energy is based on a consistent approach and suitable for providing a comparative assessment of the relative benefits

In comparison to other networks, Advisian found that:

e) Jemena's approach to apply a two stage screening process is similar to the approach adopted by other Australian distribution networks
f) The demand management applications identified through Jemena's demand management options assessments are consistent with the experience of other Australian DNSPs
g) The impact of broad-based demand management and energy efficiency measures, customer response to higher electricity prices and economic factors have, in aggregate, reduced the forecast demand growth rates across most distribution networks, resulting in fewer opportunities for demand management.

Therefore Advisian concludes that Jemena's demand management options assessment approach is comparable to the practices of other Australian distribution networks and that Jemena has demonstrated a reasonable basis for the decision not to proceed with non-network options in its documentation for the 2015 planning cycle. Jemena's historical commitment to demand management has been noted by the AER. Similarly, Advisian recognises that Jemena is actively focussed on improving its market engagement practices and providing greater transparency over the evaluation of potential non-network alternatives to augmentation.

4 Issues Raised in AER Preliminary Determination

Following from our review of Jemena's approach, this section summarises the specific issues raised in the AER's Preliminary Determination in relation to Jemena's demand management options analysis and provides Advisian's assessment of the actions that have been taken by Jemena to address these matters.

4.1 Summary of Preliminary Determination Findings

The AER's preliminary determination identified specific matters relating to the consideration of demand management options assessment. In making its determination on Jemena's forecast augmentation expenditure, the AER observed that:

> *"Jemena generally dismisses non-network options to defer major augmentation capex. Non-network options such as embedded generation and demand management can be used to prudently defer major capex (although they may not fully resolve major capacity shortages in the longer term). Jemena has not consistently carried out probabilistic cost benefit analyses to investigate the benefit of these options over the 2016-20 period"*

In addition to the AER's general observation, specific reductions were made to Jemena's augmentation capex program in relation to the following three projects:

- **Flemington Zone Substation Upgrade** was reduced from $8.2m to $0.3m to only allow the costs for new 11kV transformer cables, on the basis that the cables represent the capacity constraint at the substation[33].

  This adjustment does not relate directly to the consideration of non-network options, however Flemington is a site that was identified for detailed assessment of the demand management potential.

- **Sunbury Zone Substation Upgrade** was reduced from $14.1m to $1.3m to only allow costs for a new transformer to address the capacity constraint at the site. [34]

  This adjustment does not relate directly to the consideration of non-network options, however Sunbury is a site that was identified for detailed assessment of the demand management potential. Similarly the AER recognised that "*The forecast utilisation of the Sunbury substation is over capacity and the load on the substation is expected to increase further. This indicates that augmentation should be required to ease expected load pressures*"[35]

- **Preston Area Conversion** was reduced from $27.5m to $0m on the basis that the AER was not satisfied *"that the project is justified by the need to expand capacity or capability of the network"* [36]and that Jemena had *"not demonstrated that the scope and timing of the project is necessary to maintain network reliability, safety or security over the 2016-20 period"*[37]

  In particular, the AER considered that Jemena dismissed potential credible options to alleviate capacity concerns in 6.6kV feeders and ease pressure on aging assets (including load transfers, upgrading feeder

[33] AER, *Jemena Preliminary Determination 2016-20 Attachment 6 – Capital Expenditure*, October 2015, pp6-49 to 6-50

[34] ibid, pp.6-46 to 6-49

[35] ibid, pp.6-42

[36] ibid, pp.6-53

[37] ibid, pp.6-54

sections, building new feeder ties and adopting non-network options)[38]. The AER considered that these 'may' represent prudent lower cost options but did not make a specific allowance for any alternative.

Consequently, the specific adjustments to Jemena's augmentation capex are primarily driven by questions of the categorisation and/or scope of Jemena's proposed solutions. These matters have not been considered in Advisian's assessment of demand management options.

4.2 Advisian Assessment

Since the submission of its regulatory proposal, Jemena has documented its consideration of demand management options in its Demand Management Options Analysis report[39]. The report considers all 36 of Jemena's major augmentation capex projects in a quantitative manner by applying the process outlined in section 3 of this report.

The options analysis reports responds directly to the AER's observations regarding Jemena's dismissal of non-network options by demonstrating the process, input assumptions, analysis and evaluation of options that has been undertaken for Jemena's augmentation capex portfolio. By applying the screening process Jemena found that:

- in all but 11 of the 36 cases, demand management solutions were not a credible alternative for the proposed augmentation expenditure.
- in all but 4 of the 11 cases that passed the initial screening, demand management solutions were not practical on the basis of non-capacity factors and other practical considerations.
- in 2 of the 4 cases (Sunbury and Flemington), it was established that it is not realistic to secure the required scale of reliable, cost effective demand management to avoid the capacity constraint. However, non-network options reports have been issued for consultation in relation to these projects to test for alternative proposals.
- in the remaining 2 cases, (the HV feeders) Demand management options were found to be preferable to the network solution on the basis of the initial cost-benefit analysis, but they have not been selected as the preferred option as it is not realistic to secure the required scale of reliable, cost effective demand management in the predominantly residential areas. Further evaluation and market testing for demand management solutions will be undertaken for these HV feeders.

Advisian recognises that there may be some further scope for more detailed assessment of demand management, load transfers, mobile or embedded generation to deliver short term risk management benefits for each project. The viability of these detailed sub-options would need to be assessed to take site specific factors, specific project costs and relevant customer information into account and take into consideration the outcomes of Jemena's market testing.

Particularly in the case of relatively small augmentation projects such as the HV feeders, these investigations would typically need to occur close to the date for investment commitment to ensure that the most recent demand forecasts underpin the decision.

The following sections consider the potential for demand management for the projects identified by the AER, namely, Flemington, Sunbury and Preston, as well as for the two high voltage feeder projects.

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38 ibid

39 Jemena, *Demand Management for Deferral of Network Augmentation – Options Analysis,* 9 December 2015

4.2.1 Flemington

The AER's concerns in regard to Flemington do not relate directly to the consideration of demand management options. Notwithstanding, Flemington is one of the projects that has been identified through Jemena's options assessment process as having an energy efficiency option (NPV $372.0m) that represents comparable value to the network solution (NPV $375.4m)[40]. In cases where the capacity constraint can be addressed through a reduced scope (cost) for the project, the network solution would become more attractive relative to the demand management option (all else being equal).

Jemena rejects the energy efficiency option on the basis that deferral of the augmentation would require approximately 22MVA of demand reduction by 2021 against a total demand of 14MVA from the largest 11 customers. On this basis, it is not reasonable to expect to achieve the required demand reduction through energy efficiency measures.

Therefore despite the apparent viability of energy efficiency measures, Advisian agrees with Jemena's assessment that the most competitive demand management solution is not a realistic option in this case.

Notwithstanding the above, Jemena has published a non-network options report for this project for consultation with non-network solution providers to test the availability of alternative market based solutions.

4.2.2 Sunbury

Again, the AER's concerns in regard to Sunbury do not relate directly to the consideration of demand management options. The AER also concurs with the need for augmentation at Sunbury to address existing capacity constraints[41]. Notwithstanding, Sunbury is one of the projects that has been identified through Jemena's options assessment process as having a Demand Response option (NPV $1,683m), a mobile generation option (NPV$1,687.3m) and an energy efficiency option (NPV$1,723.1m) that represent comparable value to the network solution (NPV $1,708.0m)[42]. In cases where the capacity constraint can be addressed through a reduced scope (cost) for the project, the network solution would become more attractive relative to the demand management option (all else being equal).

Jemena rejects the demand response and energy efficiency options on the basis that deferral of the augmentation would require approximately 25MVA of demand reduction by 2021 against a total demand of 10MVA from the largest 24 customers. On this basis, it is not reasonable to expect to achieve the required demand reduction through demand response or energy efficiency measures.

Jemena also rejects mobile generation on the basis that it has an NPV $20m less than the augmentation project. Based on the analysis of mobile generation costs performed by Advisian discussed in Section 3.4.1, Jemena's cost estimates were found to be lower than indicative market

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[40] Ibid p. 19

[41] AER, *Jemena Preliminary Determination 2016-20 Attachment 6 – Capital Expenditure*, October 2015, p 6-42

[42] Jemena, *Demand Management for Deferral of Network Augmentation – Options Analysis,* 9 December 2015, p. 15

costs. Advisian agrees that it is reasonable to reject mobile generation as a viable demand management option.

Therefore despite the apparent viability of demand response, mobile generation and energy efficiency, Advisian agrees with Jemena's assessment that the most competitive demand management solution are not realistic options in this case.

Notwithstanding the above, Jemena has also published a non-network options report for this project for consultation with non-network solution providers to test the availability of alternative market based solutions.

4.2.3 Preston

Preston zone substation has not been included in the demand management options assessment as there has been no load or energy at risk forecast. Preston is a summer peaking station and Figure 4-1 below demonstrates that the peak load is forecast to be less than the normal and N-1 ratings through to 2025.

In cases where there is no load or energy at risk, demand management options do not create a benefit stream. Therefore in this situation, demand management options do not offer a credible solution to defer investment as the substation is operating below capacity.

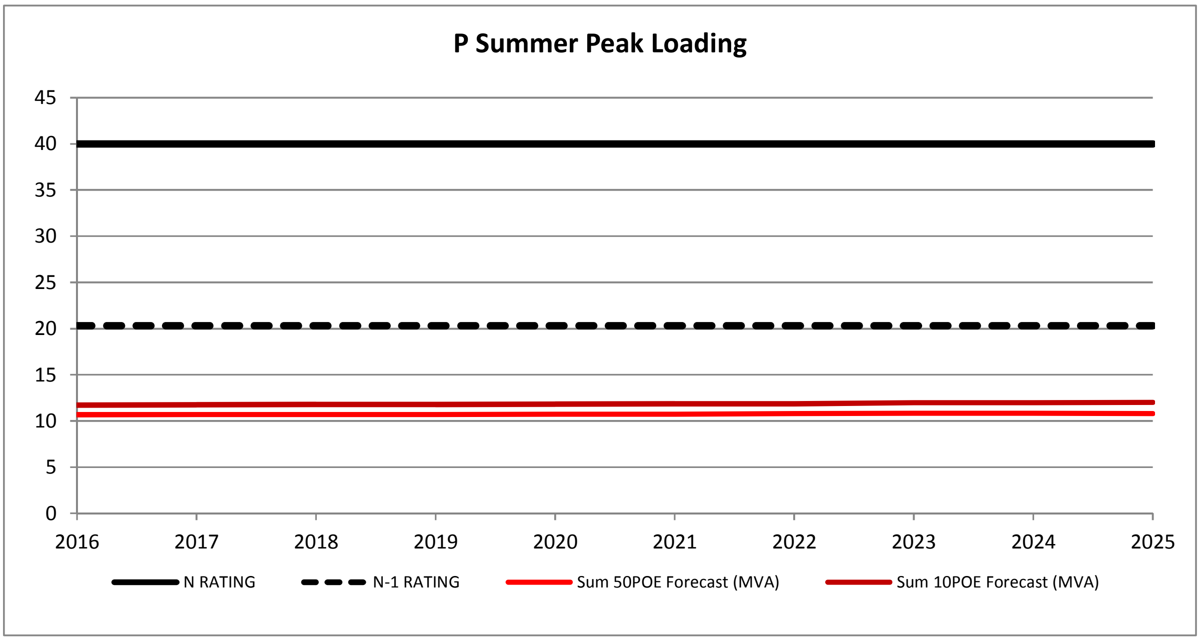

Figure 4-1 - Preston Forecast Peak Load

4.2.4 HV Feeder Projects

Augmentation capex projects on the HV feeders have been screened to identify those with potential to be deferred through the use of cost effective demand management options. Jemena's process has identified two additional feeder projects that may be addressed through a non-network solution, subject to further investigation.

Both Essendon and Heidelberg HV feeder augmentation capex projects have potential to be deferred through the use of demand management options. However, further work is proposed by Jemena to verify this potential and whether emerging demand response and energy efficiency technologies can offer increased penetration rates in largely residential areas while maintaining cost effectiveness.

Given the uncertainty surrounding whether sufficient demand management will be available on either feeder, Advisian considers that Jemena's approach to proceed with demand management investigations but retain the network solution represents a prudent response to the uncertainty in the likely outcome.

4.2.5 Summary

Advisian has reviewed Jemena's assessment of demand management options and considers that the process is reasonable on the basis of our review of the process, inputs and application of conservative assumptions in screening augmentation projects.

Given that the process followed by Jemena is reasonable, the inputs to the process are reasonable, and the application of the process is reasonable, Advisian notes that there are specific characteristics of Jemena's network and operating environment that impact demand management deployment. Factors that affect the economic implementation of demand response, energy efficiency and embedded generation to avoid specific major augmentation projects include:

- The relative ease with which the network can be 'meshed' when compared to more spatially dispersed networks. This means that network solutions (short ties between lines) are typically lower cost than in other networks where the network solution may be the duplication of the line
- The modest forecast growth rates across much of the network meaning that there is less augmentation required, but the potential for longer deferral periods may increase the overall value of demand management solutions that are found to be viable.
- The incorporation of mass market demand management, embedded generation and energy efficiency measures through the reduced growth forecast. This means that the aggregation of customer driven small scale demand management, embedded generation and Energy efficiency are incorporated in Jemena's augmentation capex forecast through the demand forecast.

Therefore Jemena's more detailed demand management and embedded generation investigations support the view that there are limited opportunities for large scale discrete demand management solutions in their network to defer major augmentation projects. This does not mean that demand management and embedded generation do not play a role in Jemena's expenditure forecast, as consumer led demand management, embedded generation and energy efficiency are reflected in the modest growth forecasts that underpin the augmentation capex forecast.

In relation to Sunbury and Flemington, Jemena's analysis has identified that non-network solutions are not realistic options. Based on our review, Advisian agrees with this position, however we note that the consultation process for the recently issued non-network option reports will test external providers for viable opportunities.

Due to the nature of the constraints at Preston and the alignment with the longer term strategy for voltage conversion in the area, there is limited opportunity for demand management because the substation is not expected to exceed its capacity.

For completeness of the analysis, Advisian considers that there may be an opportunity to refine Jemena's evaluation process in the future through the further evaluation of the use of hired mobile generator sets to facilitate short term deferral. This would represent a market priced opex-capex trade off and would provide greater flexibility in deployment as Jemena would not incur the full cost of generation assets. However, Advisian's assessment of costs in section 3.4.1 found that costs for hired generation are likely to be significantly higher where generation is required over an extended period. We also note that mobile generation options would usually incur site acquisition (or lease) costs, planning approvals and connection costs which may exceed the cost for augmentation or extend the timeframe for implementation to the point that the option is no longer viable, particularly for short term applications.

4.3 Conclusions

In relation to the specific matters that were raised by the AER in relation to Jemena's demand management options assessment practices, Advisian concludes that:

a) Jemena has reviewed and improved the transparency of the quantitative process that has been used to evaluate potential non-network options to demonstrate the reasons for not proceeding with non-network options for augmentation projects.
b) the quantitative analysis conducted during the 2015 planning cycle supported Jemena's initial view that there were limited options beyond those identified in the 2014 DAPR and accepted by the AER as an efficient opex step change.
c) demand management options do not represent a realistic alternative for Flemington or Sunbury zone substations due to the scale of demand management that is required.
d) Jemena has commenced the consultation for non-network options for the Flemington and Sunbury zone substation projects which will test whether the external market can provide an alternative solution prior to commitment to network augmentation.
e) demand management options do not address the underlying need for the Preston conversion project as the substation is not expected to operate outside its N-1 rating.

Advisian considers that Jemena's option analysis document and the associated planning analysis demonstrates that Jemena considers demand management options for all of its major augmentation capex Projects. Therefore, our findings oppose the AER's criticisms of JEN's approach to assessing non-network alternatives to incurring augmentation capex. This view is supported by Jemena's historical commitment to demand management, as recognised by the AER in its commentary on the preliminary DMIS decision.

5 Conclusions

Advisian has undertaken an independent review of Jemena's demand management options assessment practices, their application in the context of the 2016-2020 expenditure forecasts and the specific matters raised in the AER's Preliminary Determination.

1. Advisian's review of Jemena's obligations under the NER to consider demand management and other non-network options has found that Jemena has complied with the specific requirements and responded to the regulatory incentives in relation to the:

a) publication of its 'Demand Side Engagement Document'
b) inclusion of a qualitative summary of its demand management initiatives in the DAPR
c) publication of Non-Network Options Reports for RIT-D projects
d) focus of the network planning process on selecting the most efficient option
e) historical implementation of Demand Management Innovation Allowance projects

2. Advisian's review of Jemena's approach to evaluating demand management options for the 2016-2020 period has found that:

a) The approach is logical, consistent with the practices of other Australian DNSPs and covers the thirty six augmentation capex projects included in Jemena's expenditure forecast
b) The inputs to the screening evaluation are reasonable for the purpose of a high level assessment, taking into account the wide margin for uncertainty that has been applied to the results
c) The review of the screening test outcomes against non-capaicty factors and practical considerations that were not specifically taken into account in the screening assessment is reasonable on the basis that opportunities for demand management are heavily dependent on the location of an emerging capacity constraint.
d) The probabilistic approach to the calculation of expected unserved energy is based on a consistent approach and suitable for providing a comparative assessment of the relative benefits

3. In comparison to other networks, Advisian found that:

a) Jemena's approach to apply a two stage screening process is similar to the approach adopted by other Australian distribution networks.
b) The limited demand management applications identified through Jemena's demand management options assessments are consistent with the experience of other Australian DNSPs
c) The impact of broad-based demand management and energy efficiency measures, customer response to higher electricity prices and economic factors have, in aggregate, reduced the forecast demand growth rates across most distribution networks, resulting in fewer opportunities for demand management.

4. In relation to the specific matters that were raised by the AER in relation to Jemena's demand management options assessment practices, Advisian concludes that:

a) Jemena has reviewed and improved the transparency of the quantitative process that has been used to evaluate potential non-network options to demonstrate the reasons for not proceeding with non-network options for augmentation projects.
b) the quantitative analysis conducted during the 2015 planning cycle supported Jemena's initial view that there were limited options beyond those identified in the 2014 DAPR and accepted by the AER as an efficient opex step change.
c) demand management options do not represent a realistic alternative for Flemington or Sunbury zone substations due to the scale of demand management that is required.
d) Jemena has commenced the consultation for non-network options for the Flemington and Sunbury zone substation projects which will test whether the external market can provide an alternative solution prior to commitment to network augmentation.
e) demand management options do not address the underlying need for the Preston conversion project as the substation is not expected to operate outside its N-1 rating.

Advisian considers that Jemena's option analysis document and the associated planning analysis demonstrates that Jemena considers demand management options for all of its major augmentation projects, including documenting the reasons for not proceeding with a non-network option at each stage of the assessment.

Appendix A

Jemena Report

Demand Management for Deferral of Network Augmentation – Options Analysis

Jemena Electricity Networks (Vic) Ltd

Demand Management for Deferral of Network Augmentation

Options Analysis

ELE-PL-0055

Public

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Jemena

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Authorisation

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GLOSSARY

Augex	Augmentation related capital expenditure.
Battery storage	Use of batteries to store energy during low electricity demand periods, or from solar generation, and discharge during peak demand periods.
Capex	Capital expenditure.
Demand Management	Reduction of electricity demand experienced by an asset through any action that reduces demand. Includes Demand Response, embedded generation, mobile generation and energy efficiency.
Demand Response	Actions taken by customers to reduce electricity demand on receipt of an instruction.
Embedded generation	Generation that is embedded in the electricity network, usually on the customer side of the revenue meter. Includes cogeneration, emergency generators and Solar PV.
Energy efficiency	Improvements to electricity consuming equipment or processes to reduce consumption.
Energy storage	Use of a storage system to store energy during low electricity demand periods, or from solar generation, and discharge during peak periods. Includes capacitors, flywheels, pumped water storage (hydro), compressed air and battery systems. Storage can be located on the electricity network (centralised) or customer premises (distributed).
Mobile generation	Generation units, usually diesel fuelled, brought in to provide network support by reducing demand. These units can be moved to new locations as required.
Opex	Operational expenditure
Solar PV	Solar Photovoltaic panels are used to generate electricity directly from solar energy. Commercial and domestic scale Solar PV is usually behind the customer meter (embedded generation) and can reduce measured demand.

ABBREVIATIONS

AER	Australian Energy Regulator
BD	Broadmeadows Zone Substation
CAT	Constraint Analysis Tool (Greensync software)
DAPR	Distribution Annual Planning Report
DR	Demand Response
DM	Demand Management
DNSP	Distribution Network Service Provider
EDPR	Electricity Distribution Price Review
ES	Essendon Zone Substation
EUSE	Expected Unserved Energy
FT	Flemington Zone Substation
HB	Heidelberg Zone Substation
HV	High Voltage
JEN	Jemena Electricity Networks
kVA	Kilo volt ampere (1,000 volt ampere)
kW	Kilo watt (1,000 watts)
LED	Light Emitting Diode
LV	Low Voltage
MVA	Mega volt ampere (1,000,000 volt ampere)
MW	Mega watt (1,000,000 watts)
MWh	Mega watt hour (1,000,000 watt hours)
NCP&A	Network Capacity Planning and Assessment (Jemena team)
NPV	Net Present Value
PV	(Solar) Photovoltaic
SBY	Sunbury Zone Substation
VCR	Value of Customer Reliability
ZS	Zone Substation

OVERVIEW

Jemena Electricity Networks (JEN) submitted its forecast 2016-2020 augmentation capital expenditure (augex), supported by the Distribution Annual Planning Report (DAPR)[1] and Network Development Strategies, to the Australian Energy Regulator (AER) in April 2015 as part of the 2016-2020 Electricity Distribution Price Review (EDPR) submission. This report presents an overview of the methodology which has been applied to identify opportunities to prudently defer major augex through demand management. The report also presents detailed cost benefit analysis for those demand management opportunities which are considered most likely to achieve deferral benefits in practice.

Six demand management options have been considered:

1. Demand Response – reduction in demand by customers on receipt of a signal;
2. Mobile Generation (diesel) – Jemena installed generators used to reduce demand on the network asset;
3. Embedded Generation (diesel) – customer owned cogeneration or emergency generators operated on receipt of a signal;
4. Energy Storage (batteries) – Jemena or service provider installed battery banks to reduce demand on the network asset;
5. Solar Photovoltaics (PV) – Jemena subsidised PV installations on industrial or commercial facilities providing generation to reduce demand on the asset during peak periods; and
6. Energy Efficiency – Jemena subsidised energy efficiency projects to reduce demand on the asset throughout the year.

The methodology applied to identify opportunities to defer network augmentation through demand management consisted of:

- Task 1 – development of basis for costing each of the six demand management options considered.
- Task 2 – apply high level screening process to identify opportunities for deferral of network augmentation through demand management;
- Task 3 – undertake detailed cost benefit analysis on those opportunities most likely to achieve network deferral benefits in practice.

Using this methodology, the following four projects were selected for detailed cost benefit analysis:

- Redevelopment of Sunbury Zone Substation;
- Flemington Zone Substation capacity upgrade;
- New feeder – HB-21; and
- Reconfigure feeder – ES-23.

The conclusions from this analysis were as follows:

[1] Jemena Electricity Networks (Vic) Ltd. "2014 Distribution Annual Planning Report".

- Demand management is not a cost effective means of deferring the Sunbury and Flemington Zone Substation augmentation projects. While the energy efficiency and demand response options are shown to have a Net Present Value (NPV) comparable to the augmentation option, the significant demand reduction required cannot be achieved in practice. The capital investment required to manage the significant levels of energy at risk through battery storage or mobile generation is not considered prudent at this time.
- Demand response options are shown to have NPV's comparable to the augmentation options for the HB-21 and ES-23 feeder projects. However, even though the required demand reduction is significantly less than for the zone substation projects, the customer base in these areas is primarily residential, so reductions are unlikely to be achieved cost effectively using existing demand response aggregation technologies. There are potentially opportunities to cost effectively defer these feeder projects through a combination of demand response, energy efficiency and mobile generation but further analysis and market engagement is required to accurately cost and assess these solutions.

The next steps for this work are:

- Further evaluate and market test demand management opportunities for deferral of the HB-21 and ES-23 feeder augmentation projects; and
- Continue to develop and apply the methodology in this report to reflect new forecasts and developments in demand management technologies that could potentially reduce the costs and increase the viability of demand management options.

1. INTRODUCTION

Jemena Electricity Networks (JEN) submitted its forecast 2016-2020 augmentation capital expenditure (augex), supported by the Distribution Annual Planning Report (DAPR)[2] and Network Development Strategies, to the Australian Energy Regulator (AER) in April 2015 as part of the 2016-2020 Electricity Distribution Price Review (EDPR) submission. This report presents an overview of the methodology which has been applied to identify opportunities to prudently defer major augex through demand management. The report also presents detailed cost benefit analysis for those demand management opportunities which are considered most likely to achieve deferral benefits in practice.

1.1 OBJECTIVES

The key objectives of the work presented in this report are as follows;

- Develop a probabilistic cost benefit methodology by which to investigate the benefits of deferring network augmentation capital expenditure (augex) through demand management;
- Use developed methodology to identify opportunities to defer proposed (2016-20 period) network augmentation projects with demand management;
- Undertake detailed cost-benefit analysis on those opportunities which are considered most likely to achieve deferral benefits in practice.

1.2 DRIVERS FOR DEMAND MANAGEMENT

The drivers for this work include:

- Demand management is one of the ways that augmentation expenditure could be delayed or avoided to provide a lower cost solution for network customers;
- The rate of overall demand growth has slowed compared to previous regulatory periods. This demand growth is unevenly distributed over the Jemena network, with areas of high growth balanced by other areas of low growth or even forecast load decline. Demand management could potentially help to manage network load at risk where the demand forecast suggests that there is a risk of over-investment in network augmentation; and
- Technology to provide demand management solutions, particularly through demand response and battery storage, is evolving rapidly. Previous barriers with respect to the availability of demand management in a network area, for example the requirement for significant industrial and commercial loads for a demand response programme to be viable, could be diminished, offering greater load management opportunities and potentially lower costs.

2 Jemena Electricity Networks (Vic) Ltd. "2014 Distribution Annual Planning Report".

1.3 JEMENA'S DEMAND MANAGEMENT INITIATIVES

The work presented in this report supports a range of demand management initiatives that Jemena is undertaking including:

- Publication of a demand side engagement document and supporting register of demand management providers[3];
- Publication of non-network options reports for Flemington and Sunbury[4] – Diggers Rest electricity supply areas - these reports are the first stage of the Regulatory Investment Test for Distribution (RIT-D) process as defined by the National Electricity Rules and are a step towards active engagement with non-network providers.
- Demand response trial – Jemena (supported by Greensync Pty Ltd) is currently implementing a demand response trial to manage the network loading on the BD-13 22 kV feeder under system normal conditions. This project is an important step towards increased collaboration between Jemena and its large customers and will provide Jemena with experience in planning, implementation and operation of demand response.
- Development of Constraint Analysis Tool (CAT) - Jemena is co-developing constraint analysis software to facilitate the quantitative comparison between demand management and network augmentation options. This tool has been used in the work presented here.
- Battery grid support system study – an external consultant has been appointed to undertake a feasibility and concept design for a grid energy storage trial on the Jemena network.

3 https://jemena.com.au/industry/electricity/demand-management

4 https://jemena.com.au/industry/electricity/network-planning

2. METHODOLOGY

The methodology developed to identify opportunities to defer network augmentation using demand management is broken down into three key tasks as outlined in the following sections.

2.1 TASK 1 – DEVELOPMENT OF DEMAND MANAGEMENT COST BASIS

The cost basis used to estimate the costs for the demand management options is outlined in the following sections.

2.1.1 DEMAND RESPONSE

Demand Response (DR) is any action to reduce electrical load taken by an electricity end user in response to an instruction or price signal. End users can include industrial, commercial or domestic facilities, and actions can be at a fixed time of day, triggered by a message or automated, with pre-dispatch notification (e.g. day-ahead) or immediate.

Demand response is likely to be most cost effective when a few, short duration, peaks are expected each year. If peaks are several hours in duration or DR needs to be delivered on many days, possibly consecutively, then DR delivery percentage is likely to reduce. To manage this fatigue aspect, extra loads would need to be contracted, increasing the cost of the programme.

Table 2–1 shows the cost basis that has been used to estimate the costs of DR in Jemena's network area. These costs have been estimated from Jemena's previous experience in pricing DR options in the Craigieburn area[5]. A capacity factor of 80% has been assumed to represent the fatigue factor described above. It is also assumed that the hardware cost only applies in applications which require fast demand response.

Finally it is assumed that the DR will be provided by large commercial and industrial customers in the area with the constraint and that their combined DR would have the required impact on electricity demand. The costs to source DR from small commercial and domestic customers are likely to be significantly higher than those presented in Table 2–1. However, in future these small loads may become more cost effective as new technologies emerge for the procurement and dispatch of aggregated DR.

Table 2–1: Cost basis for demand response programs

	Unit	Value
Load available per customer	MVA	0.5
Capacity factor, delivered load vs contracted load	%	80%
Cost per customer for hardware	$	$20,000
Cost per year for programme setup	$/year	$5,000
Payments to customers for capacity	$/MVA	$20,000
Management cost for capacity	$/MVA	$10,000
Payments to customers for delivery	$/MWh	$5,000

[5] JEN "AER Query Craigieburn DR Analysis" 2015 (electronic document).

2.1.2 MOBILE GENERATION (DIESEL)

Mobile generation involves electricity generators brought in by the electricity distribution company to support the network by supplying electricity directly to the network during peak times. Mobile generators are usually diesel packaged into a shipping container size unit for ease of transportation. Gas turbines are also used but are generally more expensive and more difficult to transport. Generator engines are available in size ranges from a few hundred kilowatts (kW) to more than 10 MW. Multiple engines can be combined to form larger capacities and provide redundancy for greater reliability.

Mobile generation is likely to be most cost effective where the peak load event duration is long and the reliability of mobile generation and avoidance of the need to pay customers becomes significant. Mobile generation can be installed to suit demand requirements in terms of size and location, in contrast to demand response and embedded generation that rely on the availability, location and willingness of customers to participate with their loads or emergency generators.

The cost basis used to estimate the cost of mobile generation is summarised in Table 2–2. Diesel generation capacity is selected based on the load required in MVA. The mobile generation fixed costs are calculated over five years on the basis of purchasing and installing new units and recovering the residual value of the units at the end of that period. An annualised Net Present Value (NPV) is calculated and fuel costs are estimated based on MWh delivered. The assumption has been made that the generators will be owned and operated by a party that will receive benefit from the MWh of energy produced that will offset some of the fuel cost.

Table 2–2: Cost basis for mobile generation (diesel)

	Unit	Value
Project life	Years	5
Reliability Factor	%	100%
Annual Depreciation	%/year	15%
Installation cost as percentage of unit capex	%	40%
Commissioning cost as percentage of unit capex	%	5%
Opex cost as percentage of unit capex	%/year	3%
Diesel fuel cost	$/litre	$1
Fuel consumption	L/MWh	158
Value of peak electricity	$/MWh	$56

2.1.3 EMBEDDED GENERATION (DIESEL)

Embedded generation is any electricity generation that occurs on the end user site 'behind the meter'. This generation does not register as electricity production but reduces demand at the customer meter. Embedded generation is likely to be most cost effective in situations where the peak load needs to be managed for a small number of hours per year. If the number of hours increases, avoiding the administration cost of managing the embedded generation programme by purchasing mobile generation units is likely to be more cost effective. The applicability of embedded generation is highly dependent on the availability and reliability of emergency generators on customer sites.

The cost basis used to estimate the cost of embedded generation is summarised in Table 2–3. Operating characteristics of the generators are assumed to be the same as the mobile generators described in 2.1.2 but the actual operating characteristics of individual units will vary, particularly with respect to fuel consumption and reliability.

Capex costs are limited to those costs required to prepare the emergency generators to participate in the DM programme i.e. purchase, installation and commissioning costs are not included. Note that the reliability of the emergency generators used for this option has been reduced to 80% i.e. only 80% of the capacity contracted will be delivered. In a real world application of embedded generation, an assessment of the reliability of the available emergency generators will need to be undertaken to determine the effective capacity that will be delivered.

Generator capacity has been evaluated on 1 MVA per unit, a typical size for an emergency generator.

Table 2–3: Cost basis for embedded generation (diesel)

	Unit	Value
Project life	Years	5
Reliability Factor	%	80%
Opex cost as percentage of unit capex	%/year	3%
Diesel fuel cost	$/litre	$1
Fuel consumption	L/MWh	158
Value of peak electricity	$/MWh	$56
Investment required to prepare generators so they can operated in parallel with the grid, as percentage of unit capex for a new generator	%	10%

2.1.4 SOLAR PV

Solar PV could potentially reduce network peak demand on summer afternoons. It is unlikely to provide a benefit for winter peaks that occur in the evening. Various incentive models could be employed to achieve accelerated installation of solar PV in the required network areas. Solar PV is likely to be most attractive when the peak load is in summer and over a long period on many days of the year.

Table 2–4 shows the cost basis that has been used to estimate the costs of a solar PV demand management program. A co-investment model has been assumed, where a percentage of the capital cost of the PV installation is paid by Jemena. Solar arrays have been assumed to have a 20% capacity factor for peak demand i.e. they can be relied upon to deliver on average 20% of rated capacity during a summer peak[6]. This may be conservative and could possibly be increased by requiring west facing arrays to qualify for investment. In this model the owner of the PV system gains the revenue from all the electricity generated throughout the year and has not been included in this analysis.

[6] AusGrid "Effect of small solar Photovoltaic (PV) systems on network peak demand." 2011

Table 2–4: Cost basis for solar PV

	Unit	Value
Solar PV Peak Capacity Factor	%	20%
Cost of Solar PV (commercial scale)	$/kW	$1,360
Co-investment as percentage of total installation	%	50%
Programme cost	$/year	$5,000
Opex Costs as percentage of total installation	%/year	3%
Annual electricity generation of Solar PV in Melbourne	MWh/MW	1,314
Solar PV Peak Capacity Factor	%	20%

2.1.5 ENERGY STORAGE (BATTERIES)

Battery storage systems can be used to store energy at low demand and then discharged at periods of peak demand to alleviate network constraints. Battery storage systems can be operated throughout the year, gaining additional benefit from arbitrage of peak and off peak electricity prices. Batteries are selected based on the peak demand in MVA required (capacity) and the maximum energy to be provided in a single event (size) in MWh. The capacity determines the output of inverters required for discharge of the batteries, while the size determines the number of battery cells. Battery chemistry may also limit the rate of discharge and the percentage of energy storage that can be used to achieve a useful working life.

Battery storage is likely to be most attractive when the peak load is over a short period on many days of the year. Battery storage is unlikely to be cost effective for long duration peak loads due to the cost impact of increasing battery size to supply the energy at risk.

The cost basis used to estimate the cost of battery storage systems is summarised in Table 2–5. The capital cost of the battery storage is a combination of the inverter, battery cells, storage container and other ancillary (such as battery management system) costs. For the purposes of screening for DM opportunities, an even duration of 2 hours at the equivalent of the peak demand load at risk was assumed to size the required battery storage. In this model, the battery storage is owned and operated by Jemena so the difference between off peak and peak electricity is a benefit. The assumption is that the energy storage facility is operated throughout the year, gaining additional benefit from arbitrage of peak and off peak electricity prices.

Table 2–5: Cost basis for battery storage

	Unit	Value
Duration of maximum peak equivalent	Hours	2
Installed cost of batteries	$/kWh	$500
Installed cost of inverters	$/kVA	$150
Number of 20ft containers required for batteries	Containers/MWh	2
Cost of 20ft containers	$/container	$20,000
Fixed operating costs as a percentage of installed capital cost	%	3
Cost of off peak electricity for charging	$/MWh	$26
Value of peak electricity when discharging	$/MWh	$56

2.1.6 ENERGY EFFICIENCY

Energy efficiency can contribute to peak demand reduction by reducing demand throughout the year. It is important to select an opportunity type that is going to provide demand reduction at the appropriate time of day in the appropriate season. For example, an occupied area cooling efficiency project is unlikely to provide substantial benefits during a winter peak or after operational hours for the facility. An outdoor lighting project is unlikely to provide benefits during the summer peak due to extended daylight hours. Some energy efficiency opportunities that involve equipment upgrades can suffer from degradation over time; new pumps wear and efficiency reduces, control changes to optimise energy use can be bypassed or sensors become faulty. These can result in under delivery of peak demand reductions.

Energy efficiency projects are likely to be most attractive where the energy at risk to be managed consists of a small MVA peak load over a significant number of hours during the year. To be viable, there needs to be enough large commercial and industrial customers within the area of the constraint, that their combined projects could make the required impact on electricity demand.

The cost basis used to estimate the cost of energy efficiency programs is summarised in Table 2–6. For the purpose of this assessment, an industrial or commercial facility lighting project has been chosen as the basis, and it is assumed that the facility operates through the evening summer peak. The model for the energy efficiency cost estimates is co-investment. For example, Jemena manages a programme to find customers willing to invest 50% of the capital in a lighting project. All of the energy consumption reduction benefits will be gained by the customer.

Table 2–6: Cost basis for energy efficiency

	Unit	Value
Power factor	MVA/MWh	0.9
Operating hours	Hours/day	10
Operating days	Days/year	250
Reduction in energy usage	%	40
Wholesale peak electricity cost average for 10 hours per day operation	$/MWh	$41
Network, transmission and retail charges as percentage of wholesale price (mixture of peak and shoulder)	%	70%
Payback period of lighting upgrade	Years	4
Co-investment percentage by Jemena	%	50%

2.2 TASK 2 – IDENTIFY OPPORTUNITIES TO DEFER NETWORK AUGMENTATION

This objective of this task is to undertake high level screening of all augmentation projects proposed for the 2016-2020 regulatory period to identify those projects where deferral benefits may exist and are likely to be achievable in practice. Thirty-six capacity related augmentation projects have been proposed for the 2016-2020 regulatory period. For each of these projects the following analysis was applied:

1. Calculate benefit of deferring network augmentation project, by using the following equation:

$$Deferral\,Benefit = Project\ cost * discount\ rate * number\ of\ years\ of\ deferral$$

   Where the discount rate is assumed to be 6.24%.

2. Determine load and energy at risk – forecast demand for 2020 was used to determine energy at risk on the basis that the projects would need to be deferred beyond 2020 to be shifted out of the regulatory period. In the case of HV feeders, where energy at risk has not been determined, a nominal event duration of 2 hours at peak load has been assumed.
3. Estimate DM option costs – the DM option costs are estimated using the cost basis outlined in Section 2.1. Based on the 2020 DM option cost calculated for the load and energy at risk parameters, the lowest cost option is selected as the most effective. This calculation does not take into account whether the selected DM type is available in the required quantities in the network area being studied.
4. Assess potential for aggregation of benefits - in contrast to a network augmentation project that only provides benefits to the asset being upgraded, DM initiative benefits flow up through the electricity system, reducing peak demand for all the network elements upstream. Opportunities for aggregation of DM benefits were investigated for all of the proposed network augmentation projects.
5. Jemena Network Capacity Planning and Assessment (NCP&A) review – the NCP&A team provided feedback regarding the practical limitation of implementing demand management for the eleven projects identified by the screening process described above. Based on this feedback, the list was further reduced to four projects where it was considered that the deferral benefits were likely to be achievable in practice.

2.3 TASK 3 – COST BENEFIT ANALYSIS

The following steps were undertaken for the four projects which were selected under Task 2 for detailed cost-benefit analysis:

1. DM options development – for the high level assessment undertaken for Task 2, the DM option costs were estimated on a generic basis to compare with the value of project deferral and the value of EUSE. In Task 3, battery storage, energy efficiency, demand response and mobile generation were estimated specifically for the network constraint under consideration for the projects where it was identified to be valuable to complete detailed analysis.

2. Cost benefit analysis - To allow direct comparison of DM options to network augmentation and value of EUSE, the Net Present Value (NPV) of each option was calculated. This was achieved through the use of the Jemena Economic Cost Benefit Analysis Template. The key inputs for this model are shown in Table 2–7.

Table 2–7: Cost benefit inputs

Input	Value	Comments
Value of Expected Unserved Energy (EUSE)	Option specific	Probabilistic assessment of load and energy at risk.
Value of Customer Reliability (VCR)	$38,950/MWh	Weighted based on Jemena customer composition.
Discount rate	6.24%	
Network augmentation project capex costs	Project specific	2015 dollars including overheads.
Network augmentation project opex costs	2% of capex per annum	Internal estimate.
Network augmentation asset life	45 years	Jemena standard.
DM option capex costs	Option specific	Internal estimates supported by vendor feedback.
DM option opex costs	Option specific	Internal estimates supported by vendor feedback.
Demand response asset life	Option specific	Only available as contracted.
Energy efficiency asset life	10 years	Allow for equipment degradation and replacement.
Battery storage system asset life	10 years	Battery cycle life.

3. OPPORTUNITIES TO DEFER NETWORK AUGMENTATION

3.1 PROJECT SCREENING

As outlined in Section 2.2, each of the 35 network augmentation projects proposed for the 2016-2020 regulatory period was assessed to determine whether the DM alternative could cost effectively defer the project into the next regulatory period. The results of this assessment are detailed in Appendix A. Projects where the estimated DM costs were less than twice the value of deferring the project into the next period were highlighted for further analysis as summarised in Table 3–1.

Table 3–1: Network augmentation projects with demand management potential

Project Code	Project Name	Completion Date	Capital Cost ($k 2015)	Deferral value ($k 2015)	DM Option Cost ($k 2015)	DM Type
A43	Reconfigure Feeder – ES-23	Nov-2016	2,324	725	1,254	DR
A23	Augment steel section – SBY-14	Nov-2017	1,540	385	145	Batt
A44	New feeder - FT	Nov-2017	1,438	359	207	DR
A45	New feeder – HB-21	Nov-2017	2,457	613	580	Batt
A63	Reconfigure feeders BD-13	Nov-2017	1,482	370	605	DR
A24	Augment steel section – SBY-32	Nov-2018	1,189	223	73	Batt
A47	New feeder – NH-19	Nov-2019	1,232	154	195	DR
A89	Redevelopment Sunbury Zone Substation - SBY	Nov-2018	12,645	2,367	4,608	E Eff
A103	Redevelop Fairfield Zone Substation - FF	Nov-2018	8,820	1,651	1,544	E Eff
A74	FT Zone Substation Capacity	Nov-2017	10,426	2,602	4,393	E Eff
A35	Establish tie-line between SBY-32 and SBY-11	Nov-2017	1,254	313	290	Batt

3.2 NETWORK CAPACITY PLANNING AND ASSESSMENT REVIEW

The feedback Jemena's NCP&A team provided in relation to the practical limitations of implementing demand management in the areas of interest is summarised in Table 3–2

Table 3–2: Results of NCP&A review

Project Code	Project Name	Assess in detail?	NCP&A Feedback
A43	Reconfigure Feeder – ES-23	Y	Detailed cost benefit analysis undertaken (refer Section 4.3)
A23	Augment steel section – SBY-14	N	One of the primary drivers for this project is the conversion of single phase to three phase which cannot be realised through DM.
A44	New feeder - FT	N	The peak loading on FT is primarily driven by two major customers, Flemington Race Course and Melbourne Showgrounds, neither of which can provide DR during critical periods. Other DM options likely to be cost prohibitive.
A45	New feeder – HB-21	Y	Detailed cost benefit analysis undertaken (refer Section 4.4).
A63	Reconfigure feeders BD-13	N/A	DR trial underway (refer Section 1.3)
A24	Augment steel section – SBY-32	N	One of the primary drivers for this project is the conversion of single phase to three phase which cannot be realised through DM.
A47	New feeder – NH-19	N	Project may be deferred due to reduced demand growth.
A89	Redevelopment Sunbury Zone Substation - SBY	Y	Detailed cost benefit analysis undertaken (refer Section 4.1).
A103	Redevelop Fairfield Zone Substation - FF	N	FF is primarily a residential area so difficult to achieve required energy reductions through energy efficiency programs. Other DM options likely to be cost prohibitive.
A74	FT Zone Substation Capacity	Y	Detailed cost benefit analysis undertaken (refer Section 4.1).
A35	Establish tie-line between SBY-32 and SBY-11	N	The primary objective of this project is to facilitate load transfer during single contingency events. Without this interconnection, a DM solution would be required on each of the feeders to manage the load at risk. It is unlikely to be cost effective to duplicate battery systems across the two feeders.

3.3 SELECTED PROJECTS

Based on feedback from Jemena's NCP&A team regarding the practical limitations of implementing demand management in the areas of interest, the following projects were selected for detailed cost benefit analysis:

- Redevelopment of Sunbury Zone Substation;
- Flemington Zone Substation capacity upgrade;
- ES-23 feeder reconfiguration; and
- New HB-21 feeder.

4. COST BENEFIT ANALYSIS

4.1 SUNBURY ZONE SUBSTATION

4.1.1 IDENTIFIED NEED

Sunbury (SBY) Zone Substation comprises two 66/22 kV 10/16 MVA transformers, one 66/22 kV 10 MVA transformer and three 22 kV buses supplying six 22 kV feeders. SBY Zone Substation supplies areas of Sunbury, Diggers Rest, Bulla, Clarkefield and Gisborne South.

The existing SBY Zone Substation ratings are summarised in Table 4–1. The summer and winter capacities are limited by the 66/22 kV transformer thermal limits. In particular, the substation's overall system normal rating is limited by the capacity of the 10 MVA transformer, which doesn't allow full utilisation of the 10/16 MVA transformers due to unequal load sharing.

Table 4–1: Sunbury Zone Substation ratings

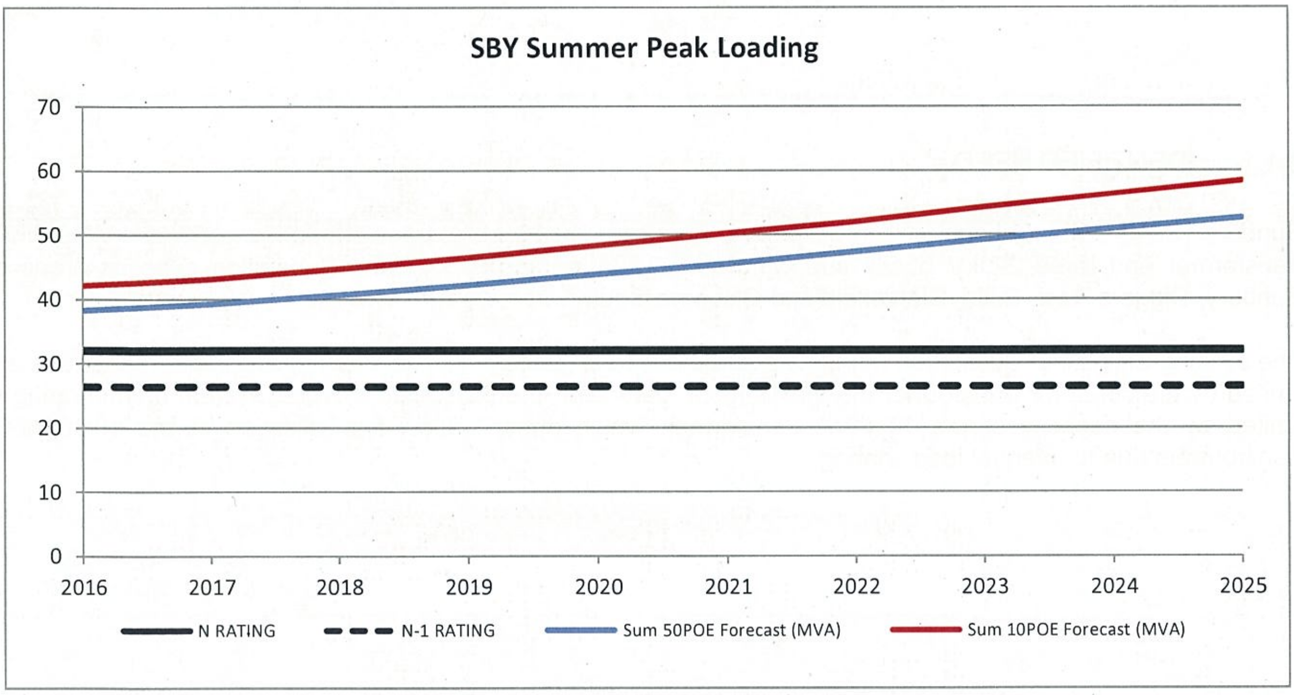
	Summer	Winter
Substation N rating	32.0 MVA	32.0 MVA
Substation N-1 rating	26.4 MVA	26.4 MVA

The load supplied by SBY Zone Substation under 10% POE and 50% POE summer maximum demand conditions already exceeds the substation's N rating as shown in Table 4–2 and Figure 4–1. The load at risk is currently being managed through load transfers to Sydenham Zone Substation, but this is not considered a long term solution.

Table 4–2: Sunbury Zone Substation energy at risk

	2016	2017	2018	2019	2020
10% POE MD (MVA)	42.1	43.2	44.7	46.4	48.3
Power factor at peak load (p.u)	0.99	0.99	0.99	0.99	0.99
10% POE N-1 loading (%)	160%	163%	169%	176%	183%
Max load at risk (MVA)	15.7	16.8	18.3	20.0	21.9
Hours at risk (h)	405	490	609	743	891
EUSE (MWh)	127.0	171.7	268.5	455.9	785.6
Cost of EUSE ($k)	4,875	6,594	10,309	17,504	30,164

Figure 4–1: Sunbury Zone Substation summer maximum demand load



4.1.2 NETWORK AUGMENTATION

The "Sunbury – Diggers Rest Growth Corridor Network Development Strategy"[7] identifies the preferred network augmentation option to address the capacity constraint at SBY Zone Substation is redevelopment of the substation. This involves replacement of the existing 10 MVA transformer with a new 20/33 MVA transformer and installation of new 66 kV and 22 kV switchgear. The proposed network augmentation has a capital expenditure estimate of $12.6 million and is planned to be implemented by November 2018 to provide benefit from summer 2019.

4.1.3 DEMAND MANAGEMENT OPTIONS ANALYSIS

Table 4–3 summarises the required capacity and annual capital costs for the four demand management options that have been considered to address the capacity constraint at SBY Zone Substation. Note that each of these options has been sized to manage all load at risk on the zone substation so the value of EUSE is zero.

[7] Jemena Electricity Networks (Vic) Ltd "Sunbury – Diggers Rest Growth Corridor Network Development Strategy (ELE-PL-0030)" 23 December 2014.

Table 4–3: Sunbury Zone Substation demand management options

	2016	2017	2018	2019	2020
Demand Response (DR)					
Standard DR (MVA)	10	13	13	17	17
Fast DR (MVA)	6	8	8	11	11
Annual Cost ($k)	320	5,492	8,416	12,915	18,534
Energy Efficiency					
Required demand reduction (MVA)	16	16	19	19	25
Annual Cost ($k)	7,000	1,310	0	2,600	0
Battery Storage					
Battery Rating (MVA)	15.7	16.8	18.3	20	21.9
Battery Capacity (MWh)	111	126	147	172	203
Annual Cost ($k)	15.7	16.8	18.3	20	21.9
Mobile Generation					
Rating (MVA)	16	21	21	28	28
Annual Cost ($k)	18,473	6,716	744	9,075	1,039

4.1.4 COST BENEFIT ANALYSIS

A summary of the cost benefit analysis for the network augmentation and demand management options for SBY Zone Substation is presented in Table 4–4. For each of the DM options it has been assumed that the network augmentation is deferred until 2021.

Table 4–4: Cost benefit analysis for Sunbury Zone Substation demand management options.

Option	Costs ($M)	Benefits ($M)	NPV ($M)	Rank
Network augmentation	11.2	1,719.2	1,708.0	2
Demand Response	9.8	1,693.1	1,683.3	4
Energy Efficiency	10.9	1,734.0	1,723.1	1
Battery storage	152.6	1,723.5	1,570.9	5
Mobile generation	44.3	1,731.5	1,687.3	3

It is noted that while the energy efficiency DM option has a greater NPV than the network augmentation option, it is considered infeasible in practice. The reason for this is that in order for an energy efficiency approach to be effective, there needs to be a customer base that is willing and able to implement robust energy saving measures which are large enough to deliver the required demand reduction at the appropriate time. As shown in Table 4–3, in order to address the energy at risk at SBY Zone Substation, and energy efficiency program would be required to provide up to 25 MVA of demand reduction by 2021. A preliminary assessment of commercial and industrial customers in the Sunbury area reveals that the top twenty-four customers account for only 10 MVA of demand. Therefore an energy efficiency program would need to involve large numbers of residential customers which would be more expensive to implement and unlikely to achieve long term energy savings.

Similarly demand response is considered infeasible at this time because of the large customer base that would be required to achieve over twenty MVA of demand reduction during peak load periods. If a 20% uptake rate is assumed, the large commercial and industrial customers in the area will only deliver 2 MVA of demand response. Jemena will continue to monitor progress in demand response aggregation technology as this type of innovation may make demand response for smaller customers a viable and cost effective option.

The results show that NPV for battery storage assuming the augmentation is deferred to 2021 is approximately $137 million less than the network augmentation. A separate analysis undertaken to study the sensitivity of the NPV to the network augmentation deferral period demonstrates that the longer the deferral, the less cost effective the option becomes. No scenario was identified where battery storage could be a cost effective option.

The NPV for mobile generation assuming the augmentation is deferred to 2021 is approximately $20 million less than the network augmentation. Similar to battery storage, the longer the deferral period the less cost effective the option becomes. However, further analysis has shown that using mobile generation to manage the energy at risk for the two years prior to the proposed network augmentation achieves an NPV which is comparable to just doing the augmentation.

4.2 FLEMINGTON ZONE SUBSTATION

4.2.1 IDENTIFIED NEED

Flemington (FT) Zone Substation comprises two 66/11 kV 20/30 MVA transformers, two 11 kV buses and ten 11 kV feeders. It supplies around 15,000 domestic, commercial and industrial customers in Flemington, Kensington, Ascot Vale and surrounding areas, with major customers including Flemington Race Course and Melbourne Showgrounds. The existing FT Zone Substation ratings are summarised in Table 4–5. The capacity in summer and winter is limited by the 11 kV transformer cables and the 11 kV switchboards.

Table 4–5: Flemington Zone Substation ratings

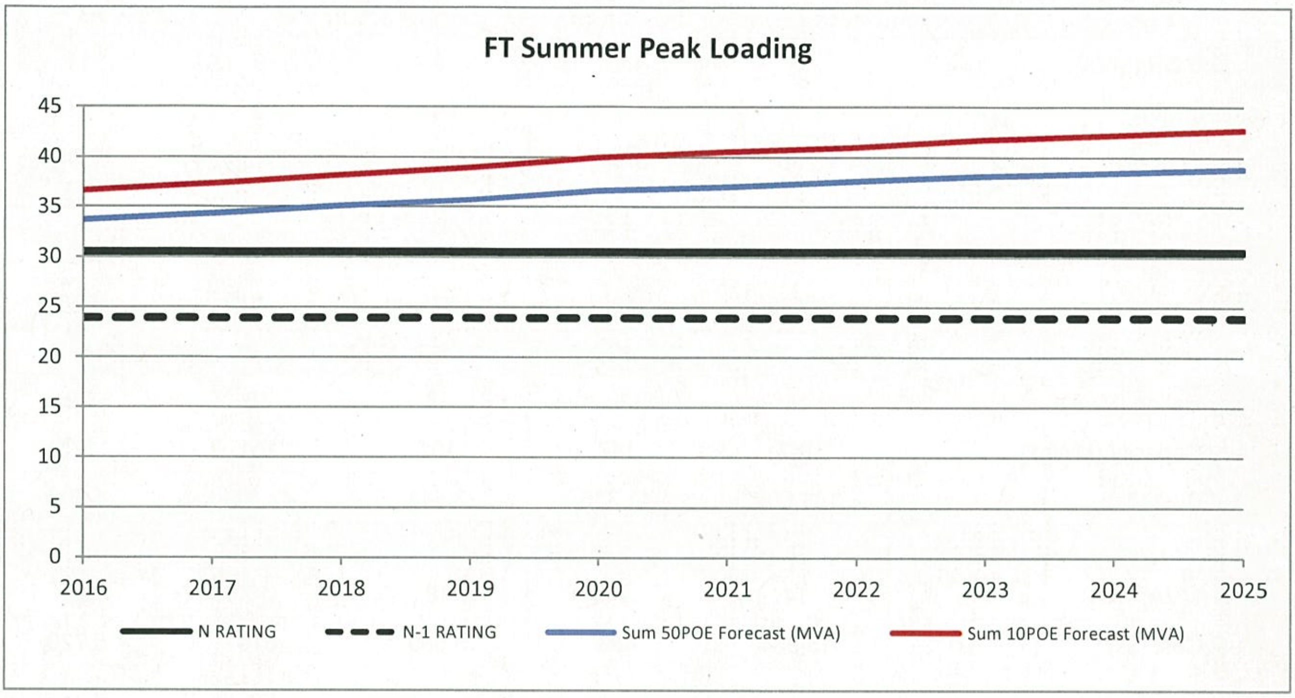
	Summer	Winter
Substation N rating	30.5 MVA	30.5 MVA
Substation N-1 rating	23.9 MVA	23.9 MVA

The load supplied by FT Zone Substation under 10% POE and 50% POE summer maximum demand conditions already exceeds the substation's N rating as shown in Table 4–6 and Figure 4–1. The load at risk is currently being managed through load transfers to Essendon Zone Substation, but this is not considered a long term solution.

Table 4–6: Flemington Zone Substation energy at risk

	2016	2017	2018	2019	2020
10% POE MD (MVA)	36.7	37.4	38.2	39.0	40.0
Power factor at peak load (p.u)	1.00	1.00	1.00	1.00	1.00
10% POE N-1 loading (%)	153%	156%	160%	163%	167%
Max load at risk (MVA)	12.8	13.5	14.3	15.1	16.1
Hours at risk (h)	1057	1301	1607	1924	2328
EUSE (MWh)	61.2	86.6	131.0	191.5	311.5
Cost of EUSE ($k)	2,349.3	3,324.5	5,030.4	7,352.4	11,959.4

Figure 4–2: Flemington Zone Substation summer maximum demand load



4.2.2 NETWORK AUGMENTATION

The "Flemington Zone Substation Network Development Strategy"[8] identifies the preferred network augmentation option to address the capacity constraint at FT Zone Substation is replacement of the 11 kV assets at FT including a 11 kV switchboards, circuit breakers and transformer cables.

The proposed network augmentation has a capital expenditure estimate of $10.4 million and is planned to be implemented by November 2017 to provide benefit from summer 2018.

4.2.3 DEMAND MANAGEMENT OPTIONS ANALYSIS

Table 4–7 summarises the required capacity and annual capital costs for the four demand management options that have been considered to address the capacity constraint at FT Zone Substation. Note that each of these options has been sized to manage all load at risk so the value of EUSE is zero.

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8 Jemena Electricity Networks (Vic) Ltd "Flemington Zone Substation Network Development Strategy (ELE-PL-0027)" 31 March 2015.

Table 4–7: Flemington Zone Substation demand management options

	2016	2017	2018	2019	2020
Demand Response (DR)					
Standard DR (MVA)	7	7	9	9	11
Fast DR (MVA)	7	7	9	9	11
Annual Cost ($k)	280	3,640	5,531	7,438	11,086
Energy Efficiency					
Required demand reduction (MVA)	14	14	18	18	22
Annual Cost ($k)	6,400	700	975	0	975
Battery Storage					
Battery Rating (MVA)	14	14	18	18	22
Battery Capacity (MWh)	147	147	161	161	175
Annual Cost ($k)	141,600	41,335	3,544	42,114	4,303
Mobile Generation					
Rating (MVA)	14	14	18	18	22
Annual Cost ($k)	15,834	483	5,569	616	5,720

4.2.4 COST BENEFIT ANALYSIS

A summary of the cost benefit analysis for the network augmentation and demand management options for FT Zone Substation is presented in Table 4–8. For each of the DM options it has been assumed that the network augmentation is deferred until 2021.

Table 4–8: Cost benefit analysis for Flemington Zone Substation demand management options.

Option	Costs ($M)	Benefits ($M)	NPV ($M)	Rank
Network augmentation	8.3	382.6	374.4	1
Demand Response	6.9	353.3	346.3	4
Energy Efficiency	13.2	385.2	372.0	2
Battery storage	216.6	370.9	154.3	5
Mobile generation	30.6	383.4	352.8	3

The results in Table 4–8 indicate that the NPV for an energy efficiency demand management program to address the FT Zone Substation energy at risk is comparable to the proposed network augmentation. However, as with to the SBY Zone Substation analysis, achieving 22 MVA of demand reduction by 2021 is not practical. An analysis of the commercial and industrial customers supplied by FT Zone substation reveals that the top 11 customers only have 14 MVA of demand in total.

The results show that NPV for battery storage assuming the augmentation is deferred to 2021 is approximately $220 million less than the network augmentation. A separate analysis undertaken to study the sensitivity of the NPV to the network augmentation deferral period demonstrates that the longer the deferral, the less cost effective the option becomes. No scenario was identified where battery storage could be a cost effective option.

The NPV for mobile generation assuming the augmentation is deferred to 2021 is approximately $22 million less than the network augmentation. Similar to battery storage, the longer the deferral period the less cost effective the option becomes. However, further analysis has shown that using mobile generation to manage the energy at risk for the two years prior to the proposed network augmentation achieves an NPV which is comparable to, if not greater, than doing the augmentation alone.

4.3 ES-23 FEEDER

4.3.1 IDENTIFIED NEED

Essendon (ES) Zone Substation has ten 11 kV feeders which supply the areas of Essendon, Moonee Ponds, Ascot Vale and Niddrie. The average feeder utilisation across the ten feeders is currently around 64% with ES-15 and ES-24 being the most heavily loaded and ES-23 being relatively lightly loaded. It is estimated that there is approximately 4.5 MVA load at risk under outage conditions due to lack of transfer capacity.

4.3.2 NETWORK AUGMENTATION

A network augmentation project has been proposed to reconfigure the ES feeders and transfer load from ES-15 and ES-24 to ES-23. It is assumed that this network augmentation will reduce the EUSE under outage conditions to zero.

Reconfiguration of the ES feeders is expected to cost $2.3 million and is planned to be implemented by November 2016 to provide benefit in summer 2017.

4.3.3 DEMAND MANAGEMENT OPTIONS ANALYSIS

Table 4–7 summarises the required capacity and annual capital costs for the four demand management options that have been considered to address the capacity constraint on the ES feeders. For the analysis, the application of DM options has been modelled using the load profile for the ES-24 feeder as it is the most heavily loaded. However, it is likely that the load profile for ES-15 will give similar results and demand reduction across both feeders will deliver similar benefits.

Table 4–9: ES-24 demand management options

	2016	2017	2018	2019	2020
Demand Response (DR)					
Standard DR (MVA)	0	0	0	0	0
Fast DR (MVA)	5	5	5	5	5
Annual Cost ($k)	494	49	50	49	49
Energy Efficiency					
Required demand reduction (MVA)	5	5	5	5	5
Annual Cost ($k)	1,937	0	0	0	0
Battery Storage					
Battery Rating (MVA)	5	5	5	5	5
Battery Capacity (MWh)	72	72	72	72	72
Annual Cost ($k)	70,300	1,352	1,352	1,352	1,352
Mobile Generation					
Rating (MVA)	5	5	5	5	5
Annual Cost ($k)	1,377	180	180	180	180

4.3.4 COST BENEFIT ANALYSIS

A summary of the cost benefit analysis for the network augmentation and demand management options for ES-24 is presented in Table 4–10. In this case the costs and benefits have been calculated relative to the network augmentation. It is assumed that EUSE for both the network augmentation and the DM options is zero. In effect this is a comparison of relatively costs as the benefits are the same for all options. For each of the DM options it has been assumed that the network augmentation is deferred until 2021.

Table 4–10: Cost benefit analysis for ES-24 demand management options.

Option	Costs ($k)	Benefits ($k)	NPV ($k)	Rank
Network augmentation	0	0	0	2
Demand Response	-146	-59	87	1
Energy Efficiency	1,343	157	-1,187	3
Battery storage	68,355	-5,855	-74,209	5
Mobile generation	604	-643	-1,247	4

The results in Table 4–10 indicate that the NPV for a demand response program to address the ES 11 kV feeder energy at risk is comparable to the proposed network augmentation. Based on the current demand forecasts, DR is likely to be even more attractive to manage the constraint on an ongoing basis, deferring the capital expenditure of the augmentation project indefinitely. Should future forecasts predict increasing demand, then the augmentation project can be implemented; should forecasts predict falling demand then the need for DR to manage the constraint may no longer be required.

In practice, it is likely to be difficult to source the required 5 MVA of demand response given the current combined peak loading on ES-15 and ES-24 is approximately 11.8 MVA and this is primarily made up of small residential loads. However, it may still be cost effective to use a combination of demand response, energy efficiency and mobile generation to defer the network augmentation to the next period, or indefinitely if the demand forecast falls in future years. Further analysis of the loads available on ES will be required to confirm the availability and costs of demand response.

4.4 HB-21 FEEDER

4.4.1 IDENTIFIED NEED

Heidelberg (HB) Zone Substation has eleven 11 kV feeders which supply the areas of Heidelberg and Ivanhoe. The average feeder utilisation across the ten feeders is currently around 71%. According to the 2014 Distribution Annual Planning Report, there is insufficient load transfer for HB-14, HB-15 and HB-22 to meet forecast demand under outage conditions. It is estimated approximately 2.2 MVA of load at risk at HB under outage conditions.

4.4.2 NETWORK AUGMENTATION

An augmentation project has been proposed to install a new 11 kV feeder HB-21 by November 2017. The new feeder will provide sufficient transfer capacity under single contingency conditions for HB-14, HB-15, HB-22 and HB-24. The project will also provide additional benefit of providing backup capability to Fairfield zone substation to support the conversion programme and new developments at the former Australian Paper Fairfield (APF) site.

The HB-21 project is estimated to cost $2.5 million.

4.4.3 DEMAND MANAGEMENT OPTIONS ANALYSIS

Table 4–11 summarises the required capacity and annual capital costs for the four demand management options that have been considered to address the capacity constraint on the HB feeders. Reducing demand on HB-24, HB-14, HB-15 and HB-22 will reduce load and energy at risk. HB-24 has been selected to analyse the DM options, being the most heavily loaded. However it is assumed that the profiles for the other HB feeders are similar to HB-24 and that the DM options can be applied across all the feeders to manage the constraint.

Table 4–11: HB-24 demand management options

	2016	2017	2018	2019	2020
Demand Response (DR)					
Standard DR (MVA)	0	0	0	0	0
Fast DR (MVA)	3	3	3	3	3
Annual Cost ($k)	310	36	36	36	36
Energy Efficiency					
Required demand reduction (MVA)	3	3	3	3	3
Annual Cost ($k)	1,162	0	0	0	0
Battery Storage					
Battery Rating (MVA)	3	3	3	3	3
Battery Capacity (MWh)	43	43	43	43	43
Annual Cost ($k)	41,995	808	808	808	808
Mobile Generation					
Rating (MVA)	3	3	3	3	3
Annual Cost ($k)	3,899	114	114	114	114

4.4.4 COST BENEFIT ANALYSIS

A summary of the cost benefit analysis for the network augmentation and demand management options for HB-24 is presented in Table 4–12. In this case the costs and benefits have been calculated relative to the network augmentation. It is assumed that EUSE for both the network augmentation and the DM options is zero. In effect this is a comparison of relatively costs as the benefits are the same for all options. For each of the DM options it has been assumed that the network augmentation is deferred until 2021.

Table 4–12: Cost benefit analysis for HB demand management options.

Option	Costs ($k)	Benefits ($k)	NPV ($k)	Rank
Network augmentation	0	0	0	2
Demand Response	-213	9	222	1
Energy Efficiency	676	166	-510	3
Battery storage	40,701	-3,427	-44,128	5
Mobile generation	3,299	-343	-3,642	4

The results in Table 4–12 indicate that the NPV for a demand response program to address the HB 11 kV feeder energy at risk is cost effective to defer the proposed network augmentation. Based on the current demand forecasts, DR is likely to be even more attractive to manage the constraint on an ongoing basis, deferring the capital expenditure of the augmentation project indefinitely. Should future forecasts predict increasing demand, then the augmentation project can be implemented; should forecasts predict falling demand then the need for DR to manage the constraint may no longer be required.

Although the required demand response of 3 MVA appears reasonable on the HB feeders which have approximately 18 MVA of load during peak periods, the load is primarily residential. Therefore it is unlikely that a demand response program would be cost effective using existing aggregation technologies. There are potentially opportunities to cost effectively defer these feeder projects through a combination of demand response, energy efficiency and mobile generation but further analysis and market engagement is required accurately cost and assess these solutions.

5. CONCLUSIONS

The conclusions from this work are:

- Demand management is not a cost effective means of deferring the Sunbury and Flemington Zone Substation augmentation projects. While the energy efficiency and demand response options are shown to have a Net Present Value (NPV) comparable to the augmentation option, the significant demand reduction required cannot be achieved in practice. The capital investment required to manage the significant levels of energy at risk through battery storage or mobile generation is not considered prudent at this time.
- Demand response options are shown to have NPV's comparable to the augmentation options for the HB-21 and ES-23 feeder projects. However, even though the required demand reduction is significantly less than for the zone substation projects, the customer base in these areas is primarily residential, so unlikely to be achieved cost effectively using existing aggregation technologies. There are potentially opportunities to cost effectively defer these feeder projects through a combination of demand response, energy efficiency and mobile generation but further analysis and market engagement is required to accurately cost and assess these solutions.

The next steps for this work are:

- Further evaluate and market test demand management opportunities for deferral of the HB-21 and ES-23 feeder augmentation projects; and
- Continue to develop and apply the methodology in this report to reflect new forecasts and developments in demand management technologies that could potentially reduce the costs and increase the viability of demand management options.

APPENDIX A 2016-2020 NETWORK AUGMENTATION PROJECTS

Project Code	Project Name	Capital Cost ($k 2015)	Deferral value ($k 2015)	DM Option Cost ($k 2015)	Potential for deferral?
A450	Establish tie-line between YVE21 and YVE22	685	214	580	No
A51	New feeder - SHM22	617	193	2,270	No
A43	Reconfigure Feeder - ES23	2,324	725	1,254	Yes
A59	Reconfigure feeders - BD4, BD3 & BMS21	387	121	498	No
A58	Reconfigure feeder - ST11 & ST22	1,307	408	1,259	No
A20	Augment CS5	236	59	580	No
A23	Augment steel section - SBY14	1,540	385	145	Yes
A44	New feeder - FT	1,438	359	207	Yes
A45	New feeder - HB21	2,457	613	580	Yes
A49	New feeder - PV11	1,985	495	1,199	No
A50	New feeder - SBY12	1,451	362	1,820	No
A54	Reconductor section of BMS12	127	32	290	No
A56	Reconfigure feeder - AW 6, 7 & 8	707	176	996	No
A63	Reconfigure feeders BD13	1,482	370	605	Yes
A24	Augment steel section - SBY32	1,189	223	73	Yes
A42	New feeder - COO23	316	59	463	No
A57	Reconfigure feeder - AW3	919	172	899	No
A30	Establish 4 feeders from CBN	1,661	207	1,410	No
A47	New feeder - NH19	1,232	154	195	Yes
A451	TMA22/AW11/AW3 reconfiguration	270	34	799	No
A60	Reconfigure feeders - CS2, CS5, CS8	831	104	594	No
A22	Augment section - TT10	514	32	198	No
A62	Reconfigure feeders across 22kV buses - BY	537	34	1,641	No
A89	Redevelopment Sunbury Zone Substation - SBY	12,645	2,367	4,608	Yes
A103	Redevelop Fairfield Zone Substation - FF	8,820	1,651	1,544	Yes
A74	FT Zone Substation Capacity	10,426	2,602	4,393	Yes

APPENDIX A 2016-2020 NETWORK AUGMENTATION PROJECTS

Project Code	Project Name	Capital Cost ($k 2015)	Deferral value ($k 2015)	DM Option Cost ($k 2015)	Potential for deferral?
A452	Land purchase - establish new Plumpton Zone Substation - PLN	2,046	128	661	No
A439	Keilor Terminal Station(KTS) to Sunbury Zone Substation (SBY) No.2 66 kV line	3,822	954	43,782	No
A237	New KTS-MAT 66kV line	10,684	2,000	24,740	No
A9	Augment BTS-NS 22kV loop	820	205	4,393	No
A17	Rearrange KTS-MAT-AW-PV-KTS 66kV loop (split loop)	7,443	1,393	24,740	No
A86	Installation of zone substation BY capacitor banks (2x8MVAr) & CBs prot & control	2,084	390	2,201	No
A83	Installation of zone substation CS capacitor bank (1x8MVAr) & CB	1,012	253	5,852	No
A84	Installation of zone substation HB capacitor bank (1x8MVAr) & CB prot & control	1,347	84	2,484	No
A85	Installation of zone substation NH capacitor bank (1x8MVAr) & CB prot & control	1,246	233	11,173	No
A35	Establish tie-line between SBY32 and SBY11	1,254	313	290	Yes