Jemena Electricity Networks (Vic) Ltd

Response to the annual Regulatory Information Notice for the 2015 regulatory year

Public

29 April 2016

7. DEMAND MANAGEMENT INCENTIVE ALLOWANCE (**DMIA**)

112. In this section, JEN responds to section 7 of Schedule 1 to the RIN for the 2015 Relevant Regulatory Year.

7.1 IDENTIFICATION OF DEMAND MANAGEMENT PROJECTS OR PROGRAMS

113. Section 7.1 of Schedule 1 to the RIN requires JEN to identify each demand management project or program which JEN seeks approval of:

114. JEN seeks approval for four projects for the 2015 Regulatory Year;

1. Demand Response Field Trial – Phase 1

JEN initiated a Demand Response Field Trial (**DRFT**) project in 2014 to develop our understanding of the benefits, costs, pricing / commercial arrangements and operational structures of customer controlled demand response (**DR**) programs. The project which included model development and desktop analysis continued into the 2015 Regulatory Year and was completed in January 2015.

2. Demand Response Trial Project on 22kV Feeder BD-13 (Phase 1)

In 2015 JEN undertook a desktop study of controlling the demand of commercial and industrial customers on one of our 22kV feeders (BD-13) as a Demand Response initiative. The desktop study included high level customer screening tests, developing a draft customer DR questionnaire, network constraint analysis, hardware requirements, Information Technology (**IT**) requirements and training JEN staff in customer acquisition. Subject to business approval, the next phase of the project will involve signing up customers and installing hardware to trial actual demand response in 2016 and 2017.

3. Demand Management Constraint Analysis Tool (CAT)

JEN initiated the development of a Demand Management Constraint Analysis Tool (**CAT**) in 2015. The software tool allows network planning engineers to undertake a consistent and objective cost benefit analysis of multiple network and non-network options. Development of the tool, which comes with advanced modelling features, continued into the 2016 Regulatory Year.

4. Grid Battery Energy Storage System Feasibility and Concept Design Study

JEN has undertaken a feasibility study into deploying a Grid Battery Energy Storage System (**GESS**) as a peak shaving technology and assessed its capability in economically addressing capacity constraints in a selected part of JEN. The project, which includes model development and desktop analysis, was completed in January 2016.

7.2 DETAILED INFORMATION – DEMAND RESPONSE FIELD TRIAL, PHASE 1

115. Section 7.2 of Schedule 1 to the RIN requires JEN to provide detailed information for each demand management project or program identified in response to section 7.1 of Schedule 1 to the RIN.

7.2.1 COMPLIANCE

116. Section 7.2(a)(i) of Schedule 1 to the RIN requires JEN to explain how JEN's initiative complies with the DMIA criteria set out in section 3.1.3 of the Demand Management Incentive Scheme (**DMIS**).

117. Expenditure associated with JEN's DRFT in Regulatory Year 2014, was approved by the AER on the basis that the DRFT meets the DMIA criteria as set out in section 3.1.3 of the DMIS. Additional expenditure was incurred in regulatory Year 2015 as this initiative was concluded in January 2015.

118. The DRFT project was initiated in 2014 to develop our understanding of the benefits, costs, pricing / commercial arrangements and operational structures of targeted demand response programmes. Phase 1 of the trial which included model development and desktop analysis continued into the 2015 Regulatory Year and was finalised in January 2015.

119. JEN considers that the continued engagement of a Demand Response technology provider in the 2015 Regulatory Year complies with DMIA criteria, set out in section 3.1.3 of the DMIS, in the following ways:

- The project is aimed at developing JEN's capabilities to reduce peak demand through customer controlled demand response projects, rather than increasing supply capacity through network augmentation (Section 3.1.3-1).
- The project is a peak demand management initiative which aims to address specific network constraints by reducing demand on the network at the location and time of the constraint (Section 3.1.3-2).
- The project deliverables are to prepare JEN for various elements of customer controlled demand response programs as an effective and efficient demand management solution (Section 3.1.3-3).
- The project is a non-tariff based project and the costs are not recovered under any other incentive scheme (Section 3.1.3-4).
- The project cost has not been recovered under other schemes. See 7.2.8 of JEN's response for more details (Section 3.1.3-5).
- The nature of expenditure is operating expenditure (Section 3.1.3-6).

7.2.2 NATURE AND SCOPE

120. Section 7.2(a)(ii) of Schedule 1 to the RIN requires JEN to explain the nature and scope of JEN's initiative.

121. The scope of work for the Demand Response Field Trial – Phase 1 includes the following key deliverables:

- **DR Benefits Model**

  The model has the necessary parameters and structures to evaluate the benefits of applying a DR solution to better manage risk across the network; specifically the ability of DR to mitigate and transfer risk (unserved energy) in two key scenarios of network asset deferrals and outage risk transfer. The pricing model described below estimates the costs of building up and operating a DR program for these two scenarios and together with the benefits the model will determine the economic viability of the solution.

- **DR Pricing Model**

The pricing model for a demand response solution includes the relevant pricing points for different classes of customers. The pricing model is developed in a form that JEN can iterate and use to determine pricing for different customer classifications in future pricing assessment of demand response solutions. The pricing model is built around each MVA of the load mitigated on a sub transmission line, associated zone substations and / or HV feeder circuits.

- **DR Operating Structures**

  The end-to-end operating structures for a typical DR solution includes options for pre- and post-contingency response, notice period, sales, contracting of load, site monitoring installations, dispatch operations, verification and settlements and implementation timeline.

122. The nature of the project is to develop our understanding of the benefits, costs, pricing / commercial arrangements and operational structures of customer controlled DR programs.

123. JEN engaged a Demand Response technology provider as a consultant to provide the deliverables in the Phase 1 project scope.

7.2.3 AIMS AND EXPECTATIONS

124. Section 7.2(a)(iii) of Schedule 1 to the RIN requires JEN to explain the aims and expectations of JEN's initiative.

125. The aims and expectations of the Demand Response Field Trial - Phase 1 project are to:

- Understand the benefits, costs and operating structures of DR as a viable demand management solution;
- Investigate DR for possible future implementation within the JEN electricity network with the objective of deferring network augmentation works or mitigating network outage risk;
- Develop JEN's capabilities in the area so as to facilitate the evaluation and implementation of DR solutions from various market providers, especially in response to JEN's regulatory investment test (RIT-D) process for large capital projects; and
- Lay the foundation for the Demand Response field trial on a 22kV feeder (BD-13), which is aimed at field trialling the learnings and validating the models developed in Phase 1.

7.2.4 SELECTION PROCESS

126. Section 7.2(a)(iv) of Schedule 1 to the RIN requires JEN to explain the process by which JEN's project was selected, including its business case and consideration of any alternatives.

127. Advances in demand management technologies and approaches represent an opportunity for JEN to manage and transfer risk in ways that have not previously been possible. By undertaking this project, JEN intends to develop and refine its approach and strategy on demand management to provide safe, reliable and cost effective solutions to its customers.

128. DR allows JEN to better manage risk across its network. The economics of doing so and specifically the ability of DR to mitigate and transfer risk (unserved energy) in two key scenarios are investigated; namely network asset deferrals and improving network reliability.

129. JEN can leverage DR to transfer network risk to customers both before and during outages reducing the overall costs of network operation. Regardless of the asset used to undertake DR (customer side generation, curtailment or storage) effective risk transfer can be achieved through DR. The cost effectiveness of risk transfer is driven by the ability of the available customer base, DR technologies, and business processes with a fast enough reaction time to mitigate the impact of network outages.

130. Any operating and contractual model implemented by JEN must be structured in such a way as to allow effective management of DR programs that support asset deferral and network reliability. The effective use of DR as a tool to support network reliability is clearly aligned to business as usual activities for network controllers as it requires a high degree of visibility and control. Likewise, utilizing DR for asset deferral can help JEN achieve the best possible economic outcome for its customers, while maintaining the same level of network reliability. Both scenarios that were investigated conform to the AER's DMIS criteria and are in line with the recommendations from the AEMC's Power of Choice review.

7.2.5 IMPLEMENTATION

131. Section 7.2(a)(v) of Schedule 1 to the RIN requires JEN to explain how JEN's initiative was implemented.

132. The works associated with the Demand Response Field Trial - Phase 1 project that were completed in 2015 have been delivered as follows:

1. Reporting and Recommendations: Prepare a technical report documenting the models developed and key parameters / structures relevant for successful implementation of a DR program.
2. Develop recommendations for field trial on a 22kV feeder (BD-13) with large commercial / industrial customers.

7.2.6 IMPLEMENTATION COSTS

133. Section 7.2(a)(vi) of Schedule 1 to the RIN requires JEN to explain the implementation costs of JEN's project.

134. The actual expenditure for the Demand Response Field Trial - Phase 1 project incurred in the 2015 Regulatory Year was $26,325, as set out in Appendix B - Template 23 (DMIS – DMIA) (Attachment 1-1 of this response to the RIN). This represented the final instalment (50%) of the contract engagement over two Regulatory Years 2014 and 2015.

7.2.7 BENEFITS

135. Section 7.2(a)(vii) of Schedule 1 to the RIN requires JEN to explain any identifiable benefits that have arisen from JEN's project, including any off peak or peak demand reduction.

136. As the Demand Response Field Trial – Phase 1 project was limited to desktop analysis and modelling, there have been no quantifiable benefits in terms of reduction in peak demand. However, the learnings from Phase 1 will be directly applicable to Phase 2 of the project where a field trial will be conducted with large commercial / industrial customers in the JEN network, subject to business approval. It is expected that there will be quantifiable benefits in terms of peak demand reduction during the operation of Phase 2.

7.2.8 ASSOCIATED COSTS

137. Section 7.2(b) of Schedule 1 to the RIN requires JEN to state whether the costs associated with JEN's initiative have been recovered under other schemes.

138. The associated costs for the development of the Demand Response Field Trial – Phase 1 are not:

- recoverable under any other jurisdictional incentive scheme,
- recoverable under any other Commonwealth or State Government scheme, and
- included in the forecast capital or operating expenditure approved in the 2011-15 Distribution Determination or recovered under any other incentive scheme in that determination.

7.2.9 FORGONE REVENUE ASSUMPTIONS AND / OR ESTIMATES

139. Section 7.2(c) of Schedule 1 to the RIN requires JEN to explain any assumptions and/or estimates used in the calculation of forgone revenue, demonstrating the reasonableness of those assumptions and/or estimates in calculating forgone revenue, including the reasons for JEN's decision to adjust or not to adjust for other factors and the basis for any such adjustments.

140. Phase 1 of the Demand Response Field Trial project is limited to a desktop analysis of DR as a viable DM solution and the development of appropriate models. JEN will field trial DR in Phase 2 of this project and therefore, JEN does not seek to recover forgone revenue resulting from the Demand Response Field Trial - Phase 1 project for the 2015 Regulatory Year.

141. As such, section 7.2(c) of Schedule 1 to the RIN is not applicable.

7.3 DETAILED INFORMATION – DEMAND RESPONSE TRIAL PROJECT ON 22KV FEEDER BD-13 (PHASE 1)

142. Section 7.2 of Schedule 1 to the RIN requires JEN to provide detailed information for each demand management project or program identified in response to section 7.1 of Schedule 1 to the RIN.

7.3.1 COMPLIANCE

143. Section 7.2(a)(i) of Schedule 1 to the RIN requires JEN to explain how JEN's initiative complies with the DMIA criteria set out in section 3.1.3 of the Demand Management Incentive Scheme (**DMIS**).

144. JEN undertook a desktop study of controlling the demand of large commercial / industrial customers on one of our 22kV feeder BD-13 as a DR initiative in 2015 to develop our understanding of the DR technology, benefits, costs, pricing / commercial arrangements and operational structures of target customers. The project included high level customer screening tests, customer DR potential questionnaire, network constraint analysis, hardware requirements, IT requirements and training of JEN staff.

145. JEN considers that the desktop study into controlling the demand of large commercial / industrial customers in the 2015 Regulatory Year complies with DMIA criteria, set out in section 3.1.3 of the DMIS, in the following ways:

- The project is aimed at developing JEN's capabilities to reduce peak demand through customer controlled demand response projects, rather than increasing supply capacity through network augmentation (Section 3.1.3-1).
- The project is a peak demand management initiative which aims to address specific network constraints by reducing demand on the network at the location and time of the constraint (Section 3.1.3-2).
- The project deliverables are to prepare JEN for various elements of customer controlled demand response programs as an effective and efficient demand management solution (Section 3.1.3-3).
- The project is a non-tariff based project and the costs are not recovered under any other incentive scheme (Section 3.1.3-4).
- The project cost has not been recovered under other schemes. See 7.3.8 of JEN's response for more details (Section 3.1.3-5).
- The nature of expenditure is operating expenditure (Section 3.1.3-6).

7.3.2 NATURE AND SCOPE

146. Section 7.2(a)(ii) of Schedule 1 to the RIN requires JEN to explain the nature and scope of JEN's initiative.

147. The scope of work for the Demand Response Trial on 22kV feeder BD-13 (Phase 1) includes the following key deliverables:

- **Constrained Analysis to Determine Target Area (feeder BD-13)**

  Assessing network risks associated with BD-13 feeder capacity constraints under various network operating scenarios, including network transfer and switching scenarios

- **High Level Customer Screening Test**

  Selecting potential commercial and industrial customers that can participate in a DR trial to be run in Regulatory Years 2016 and 2017.

- **Customer DR Potential Questionnaire**

  Developing a questionnaire that can be used to seek customers' willingness and acceptance in participating in a potential DR initiative.

- **Defining Hardware and Information Technology (IT) Requirements**

  Defining the hardware and IT requirements for controlling the demand of customers.

- **Training JEN Staff**

  Training JEN staff to undertake demand response customer acquisition activity.

148. The nature of the project is to identify ways to control the demand of commercial and industrial customers on one of our 22kV feeders (BD-13) as a Demand Response initiative.

7.3.3 AIMS AND EXPECTATIONS

149. Section 7.2(a)(iii) of Schedule 1 to the RIN requires JEN to explain the aims and expectations of JEN's initiative.

150. The aims and expectations of the Demand Response Field Trial - Phase 1 project are to:

- Understand the hardware and IT requirements of a potential DR initiative as a viable demand management solution;
- Investigate DR with the objective of deferring network augmentation works or mitigating network outage risk;
- Develop JEN's capabilities in the area so as to facilitate the evaluation and implementation of DR solutions, and
- Lay the foundation for the Phase 2 of the project in 2016 and 2017, aimed at field trialling the technology with large commercial / industrial customers on feeder BD-13.

7.3.4 SELECTION PROCESS

151. Section 7.2(a)(iv) of Schedule 1 to the RIN requires JEN to explain the process by which JEN's project was selected, including its business case and consideration of any alternatives.

152. Advances in demand management technologies represent an opportunity for JEN to manage and transfer risk in ways that have not previously been possible. By undertaking this project, JEN intends to field trial the DR on feeder BD-13 in 2016 and 2017 and refine its approach and strategy on demand management.

153. DR allows JEN to better manage risk across its network.

154. JEN can leverage DR to transfer network risk to customers both before and during outages reducing the overall costs of network operation. Regardless of the asset used to undertake DR (customer side generation, curtailment or storage) effective risk transfer can be achieved through DR. The cost effectiveness of risk transfer is driven by the ability of the available customer base, DR technologies, and business processes with a fast enough reaction time to mitigate the impact of network outages.

155. Any operating and contractual model implemented by JEN must be structured in such a way as to allow effective management of DR programs that support asset deferral and maintain network reliability. The effective use of DR as a tool to support network reliability is clearly aligned to business as usual activities for network controllers as it requires a high degree of visibility and control. Likewise, utilizing DR for asset deferral can help JEN achieve the best possible economic outcome for its customers, while maintaining the same level of network reliability.

7.3.5 IMPLEMENTATION

156. Section 7.2(a)(v) of Schedule 1 to the RIN requires JEN to explain how JEN's initiative was implemented.

157. The works associated with the Demand Response Trial Project on 22kV feeder BD-13 (Phase 1) that were completed in 2015 have been delivered as follows:

1. Assessing network risks associated with BD-13 feeder capacity constraints under various network operating scenarios, including network transfer and switching scenarios
2. Identify the aspects of controlling demand of commercial and industrial customers on feeder BD-13 that are most relevant for JEN and seek potential project partners with industry expertise.
3. Developing a questionnaire that can be used to seek customers' willingness and acceptance in participating in a potential DR initiative.
4. Selecting commercial and industrial customers that can participate in a DR trial to be run in Regulatory Years 2016 and 2017.
5. Defining the hardware and IT requirements for controlling the demand of customers.
6. Training of JEN Staff

7.3.6 IMPLEMENTATION COSTS

158. Section 7.2(a)(vi) of Schedule 1 to the RIN requires JEN to explain the implementation costs of JEN's project.

159. The actual expenditure for the Demand Response Trial Project on 22kV feeder BD-13 (Phase 1) incurred in the 2015 Regulatory Year was $10,955, as set out in Appendix B - Template 23 (DMIS – DMIA) (Attachment 1-1 of this response to the RIN).

7.3.7 BENEFITS

160. Section 7.2(a)(vii) of Schedule 1 to the RIN requires JEN to explain any identifiable benefits that have arisen from JEN's project, including any off peak or peak demand reduction.

161. As the Demand Response Trial on 22kV feeder BD-13 (Phase 1) was limited to desktop analysis, there have been no quantifiable benefits in terms of reduction in peak demand. However, the learnings from the project will be directly applicable to Phase 2 of the project where a field trial will be conducted with large commercial / industrial customers on the feeder in 2016 and 2017. It is expected that there will be identifiable benefits in terms of peak demand reduction during the operation of Phase 2.

7.3.8 ASSOCIATED COSTS

162. Section 7.2(b) of Schedule 1 to the RIN requires JEN to state whether the costs associated with JEN's initiative have been recovered under other schemes.

163. The associated costs for the development of the Demand Response Trial Project on 22kV feeder BD-13 (Phase 1) are not:

- recoverable under any other jurisdictional incentive scheme,
- recoverable under any other Commonwealth or State Government scheme, and
- included in the forecast capital or operating expenditure approved in the 2011-15 Distribution Determination or recovered under any other incentive scheme in that determination.

7.3.9 FORGONE REVENUE ASSUMPTIONS AND / OR ESTIMATES

164. Section 7.2(c) of Schedule 1 to the RIN requires JEN to explain any assumptions and/or estimates used in the calculation of forgone revenue, demonstrating the reasonableness of those assumptions and/or estimates in calculating forgone revenue, including the reasons for JEN's decision to adjust or not to adjust for other factors and the basis for any such adjustments.

165. Phase 1 of the Demand Response Trial Project on 22kV feeder BD-13 is limited to a desktop assessment of DR technology as a viable DM solution. JEN will field trial DR in Phase 2 of this project and therefore, JEN does not seek to recover forgone revenue resulting from the Demand Response Trial on 22kV feeder BD-13 (Phase 1) for the 2015 Regulatory Year.

As such, section 7.2(c) of Schedule 1 to the RIN is not applicable.

7.4 DETAILED INFORMATION – DEMAND MANAGEMENT CONSTRAINT ANALYSIS TOOL (CAT)

166. Section 7.2 of Schedule 1 to the RIN requires JEN to provide detailed information for each demand management project or program identified in response to section 7.1 of Schedule 1 to the RIN.

7.4.1 OBLIGATIONS OR REQUIREMENTS

167. Section 7.2(a)(i) of Schedule 1 to the RIN requires JEN to explain how JEN's initiative complies with the DMIA criteria set out in section 3.1.3 of the Demand Management Incentive Scheme (**DMIS**).

168. JEN initiated the development of a Demand Management Constrained Analysis Tool (CAT) in association with a demand response technology provider in 2015. The software tool allows network planning engineers compare costs and benefits of multiple network and non-network options and undertake a consistent cost benefit analysis of options.

169. JEN considers that the development of a Demand Management CAT in the 2015 Regulatory Year complies with DMIA criteria, set out in section 3.1.3 of the DMIS, in the following ways:

- The tool allows network planning engineers apply a consistent approach in analysing and comparing multiple network and non-network options (Section 3.1.3-1).
- The project is a broad based Demand Management cost-benefit analysis initiative, and is not aimed at a specific location on the network (Section 3.1.3-2).
- The project deliverable is a software tool which can be used to develop and enhance JEN's capability in comparing and analysing multiple network and non-network options. In return to the upfront capital contribution and co-development effort, JEN can subscribe to the use of the software tool at a discounted price for the next two years after the completion of the development. No commercially available software package that allows the user to apply probabilistic planning methodology to assess the economic benefits of multiple non-network and network augmentation options is currently available (Section 3.1.3-3).
- The project is a non-tariff based project and the costs are not recovered under any other incentive scheme (Section 3.1.3-4).
- The project cost has not been recovered under other schemes. See 7.4.8 of JEN's response for more details (Section 3.1.3-5).
- The nature of expenditure is operating expenditure (Section 3.1.3-6).

7.4.2 NATURE AND SCOPE

170. Section 7.2(a)(ii) of Schedule 1 to the RIN requires JEN to explain the nature and scope of JEN's initiative.

171. The nature of the project is to develop a software tool that allows network planning engineers apply a consistent approach in analysing and comparing multiple network and non-network options.

172. The scope of works for the project includes developing a software tool with the following capabilities:

- Advanced modelling of network options, including capability to assess benefits under various network operating scenarios, including network transfer and switching scenarios.
- Advanced modelling of non-network options, including capability to assess benefits under various Demand Management asset types, various Demand Management portfolios and various network operating scenarios, including network transfer and switching scenarios.
- View year-on-year tabulated cost benefit for the duration of the forecasts.
- View the optimal deferral length in a chart format.
- Export of the results of analysis to other documents, e.g., Business Cases.

173. JEN has engaged a Demand Response technology provider as a consultant to develop the tool and provide the deliverables in the project scope.

7.4.3 AIMS AND EXPECTATIONS

174. Section 7.2(a)(iii) of Schedule 1 to the RIN requires JEN to explain the aims and expectations of JEN's initiative.

175. The aims and expectations of the project are to:

- Develop a software tool that allows costs and benefits of multiple network and non-network options be considered.
- Develop a framework and methodology for a consistent and objective cost benefit analysis of multiple network and non-network options.

7.4.4 SELECTION PROCESS

176. Section 7.2(a)(iv) of Schedule 1 to the RIN requires JEN to explain the process by which JEN's project was selected, including its business case and consideration of any alternatives.

177. To allow demand management options to be considered on the same basis as traditional network options, JEN needs

- Support Demand Management objectives of the business by developing a more advanced cost benefit analysis tool that can be applied to both network and non-network options.
- Adopting a more accurate cost benefits analysis tool for both network and non-network options with advanced network and Demand Management scenario modelling capability.

7.4.5 IMPLEMENTATION

178. Section 7.2(a)(v) of Schedule 1 to the RIN requires JEN to explain how JEN's initiative was implemented.

179. JEN surveyed the market and did not find a commercially available software package that allows the user to apply probabilistic planning methodology to assess the economic benefits of multiple non-network and network augmentation options. JEN decided to team up with a demand response technology provider to develop the tool. This collaborative approach allows JEN's knowledge on grid side issues and network considerations be combined with the Consultant's expertise of Demand Response technology.

180. The works associated with the Demand Management CAT that were completed in 2015 have been delivered as follows:

- Develop a Demand Management CAT trial version with the following capabilities:
  - Input of constraint load shapes;
  - Input of load growth forecasts;
  - Calculation of benefits (Energy at Risk and Expected Unserved Energy);
  - Model network augmentation options (including Capacity benefits calculator);
  - Model DSM solution options (including Capacity benefits calculator);
  - Cost / Benefit analysis of options and comparison.
- Develop a Demand Management CAT production version with advanced modelling capabilities:
  - Advanced modelling of network augmentation options, including network transfer and switching benefits calculation;

- Advanced modelling of Demand Management solution options, including advanced Demand Management asset types, advanced Demand Management portfolios and advanced network transfer and switching benefits calculation;
- Auto-optimisation of Demand Management solution scale and deferral length;
- Effectiveness factors for sub-transmission and transmission constraints;
- Parent-child network modelling allowing the benefits of a Demand Management solution to be bridged across the feeder, zone substation and sub-transmission network.

181. This activity continued into the 2016 Regulatory Year and was completed in January 2016.

7.4.6 IMPLEMENTATION COSTS

182. Section 7.2(a)(vi) of Schedule 1 to the RIN requires JEN to explain the implementation costs of JEN's project.

183. The actual expenditure for the Demand Management CAT project incurred in the 2015 Regulatory Year was $29,814, as set out in Appendix B - Template 23 (DMIS – DMIA) (Attachment 1-1 of JEN's response). This represented the first payment (50%) of the contract engagement over two Regulatory Years 2015 and 2016.

7.4.7 BENEFITS

184. Section 7.2(a)(vii) of Schedule 1 to the RIN requires JEN to explain any identifiable benefits that have arisen from JEN's project, including any off peak or peak demand reduction.

185. As the production version of the Demand Management CAT was only delivered in January 2016, there have been no quantifiable benefits associated with this project in Regulatory Year 2015.

7.4.8 ASSOCIATED COSTS

186. Section 7.2(b) of Schedule 1 to the RIN requires JEN to state whether the costs associated with JEN's initiative have been recovered under other schemes.

187. The associated costs for the development of Demand Management CAT are not:

- recoverable under any other jurisdictional incentive scheme,
- recoverable under any other Commonwealth or State Government scheme, and
- included in the forecast capital or operating expenditure approved in the 2011-15 Distribution Determination or recovered under any other incentive scheme in that determination.

7.4.9 FORGONE REVENUE ASSUMPTIONS AND / OR ESTIMATES

188. Section 7.2(c) of Schedule 1 to the RIN requires JEN to explain any assumptions and/or estimates used in the calculation of forgone revenue, demonstrating the reasonableness of those assumptions and/or estimates in calculating forgone revenue, including the reasons for JEN's decision to adjust or not to adjust for other factors and the basis for any such adjustments.

189. The Demand Management CAT, delivered in January 2016, is currently undergoing tests by network planning engineers. Therefore, JEN does not seek to recover forgone revenue resulting from the Demand Management CAT project for the 2015 Regulatory Year.

190. As such, section 7.2(c) of Schedule 1 to the RIN is not applicable.

7.5 DETAILED INFORMATION – GRID BATTERY ENERGY STORAGE SYSTEM - FEASIBILITY AND CONCEPT DESIGN STUDY

191. Section 7.2 of Schedule 1 to the RIN requires JEN to provide detailed information for each demand management project or program identified in response to section 7.1 of Schedule 1 to the RIN.

7.5.1 COMPLIANCE

192. Section 7.2(a)(i) of Schedule 1 to the RIN requires JEN to explain how JEN's initiative complies with the DMIA criteria set out in section 3.1.3 of DMIS.

193. JEN initiated a GESS feasibility and design study in 2015 to develop our understanding of utility scale energy storage technology in mitigating peak demand network constraints and its impact on the distribution network and the quality of electricity supply.

194. JEN considers that the feasibility study into the deployment of GESS as a peak shaving technology in the 2015 Regulatory Year complies with DMIA criteria, set out in section 3.1.3 of the DMIS, in the following ways:

- The project is aimed at developing JEN's capabilities to reduce peak demand in constrained parts of the network, rather than increasing supply capacity through network augmentation (Section 3.1.3-1).
- The project is a peak demand management initiative which aims to address specific network constraints by reducing demand on the network at the location and time of the constraint (Section 3.1.3-2).
- The project deliverables are to develop JEN's capability in deploying GESS as an effective, economic and efficient peak demand management solution. The primary objectives of the GESS feasibility and design study was to develop load data analysis and battery control simulation tools which enable JEN to do high level design and assessment of GESSs as part of BAU planning processes (Section 3.1.3-3).
- The project is a non-tariff based project and the costs are not recovered under any other incentive scheme (Section 3.1.3-4).
- The project cost has not been recovered under other schemes. See 7.5.8 of JEN's response for more details (Section 3.1.3-5).
- The nature of expenditure is operating expenditure (Section 3.1.3-6).

7.5.2 NATURE AND SCOPE

195. Section 7.2(a)(ii) of Schedule 1 to the RIN requires JEN to explain the nature and scope of JEN's initiative.

196. The nature of the project is to develop our understanding of utility scale energy storage technology in mitigating peak demand network constraints, its impact on the distribution network and the quality of electricity supply, with particular focus on the application to the suburban distribution network of JEN.

197. The scope of works for the GESS Feasibility and Concept Design Study includes the following key deliverables:

- Develop a concept design for a multi-feeder GESS for an area of the network constrained by sub-transmission, zone substation and distribution feeders
- Determine an optimum size of a multi-feeder GESS. This is achieved by analysing historical load and daily load curves and developing a number of load and daily load curve forecast as the basis for determining an optimum size for batteries.
- Design and simulate a distributed energy management system for the multi-feeder GESS.

- Analyse and assess the impact of the GESS on the network.
- Estimate cost of implementing the multi-feeder GESS
- Assess the economic benefits of the GESS, including potential deferment or avoidance of large capital expenditure.
- Develop a framework for the planning assessment of GESS as a peak demand management tool.

198. JEN engaged a consulting firm as a consultant to provide the deliverables in the project scope.

7.5.3 AIMS AND EXPECTATIONS

199. Section 7.2(a)(iii) of Schedule 1 to the RIN requires JEN to explain the aims and expectations of JEN's initiative.

200. The aims and expectations of the GESS Feasibility and Concept Design Study are to:

- Understand the benefits, costs and operating modes of the GESS as a viable peak demand management solution;
- Investigate GESS technology for possible future implementation within the JEN electricity network with the objective of deferring network augmentation works or mitigating network outage risk. Note while a number of grid storage pilot or demonstration projects have been initiated by electricity distribution companies, the majority of these are targeted in "edge-of-grid" applications where battery economics are comparable to network augmentation costs. This is not the case for JEN's predominantly suburban electricity network;
- Develop JEN's capabilities in the area so as to facilitate the evaluation and implementation of GESS solutions from various technology providers.
- Lay the foundation for a GESS field trial project.

7.5.4 SELECTION PROCESS

201. Section 7.2(a)(iv) of Schedule 1 to the RIN requires JEN to explain the process by which JEN's project was selected, including its business case and consideration of any alternatives.

- Advances in GESS technologies represent an opportunity for JEN to manage network risks associated with capacity constraints in ways that have not previously been possible. By undertaking this project, JEN intends to develop and refine its approach and strategy on cost effective peak demand management solutions.
- GESS has the potential for economic management of network risks associated with capacity constraint.
- JEN can leverage GESS to manage network risk both before and during outages and potentially reduce the overall costs of network operation.
- Utilising GESS for asset deferral can help JEN achieve the best possible economic outcome for its customers, while maintaining the same level of network reliability.

7.5.5 IMPLEMENTATION

202. Section 7.2(a)(v) of Schedule 1 to the RIN requires JEN to explain how JEN's initiative was implemented.

203. JEN has taken a collaborative approach with the Consultant on this project, where JEN's knowledge on grid side issues and network considerations is combined with the Consultant's expertise on energy storage design and solutions.

204. The works associated with the GESS Feasibility and Concept Design Study that were completed in 2015 have been delivered as follows:

- Selection of a part of JEN network constrained by sub-transmission, zone substation and distribution feeder capacity and development of network models for energy flow analysis.
- Development of concept designs for multi-feeder GESS.
- Design, development and simulation of two distributed control systems.
    - A Parallel Distributed Control System for GESS (battery and inverter)
    - A Parallel Distributed Control System for the upstream network.
- Development of models including key parameters and GESS operating modes relevant for successful implementation of a trial project.
- Complete an economic assessment of the GESS option and compare with traditional network solutions
- Preparation of a report documenting the project findings

205. This activity continued into the 2016 Regulatory Year and was completed in January 2016.

7.5.6 IMPLEMENTATION COSTS

206. Section 7.2(a)(vi) of Schedule 1 to the RIN requires JEN to explain the implementation costs of JEN's project.

207. The actual expenditure for the GESS Feasibility and Concept Design Study incurred in the 2015 Regulatory Year was $27,400, as set out in Appendix B - Template 23 (DMIS – DMIA) (Attachment 1-1 of this response to the RIN). This represented the first payment (55%) of the contract engagement over two Regulatory Years 2015 and 2016.

7.5.7 BENEFITS

208. Section 7.2(a)(vii) of Schedule 1 to the RIN requires JEN to explain any identifiable benefits that have arisen from JEN's project, including any off peak or peak demand reduction.

209. As the GESS Feasibility and Concept Design Study was limited to desktop modelling, analysis and simulation, there have been no quantifiable benefits in terms of reduction in peak demand. However, the learnings from the study will be directly applicable when JEN begins a trial deployment of a GESS in a constrained part of JEN.

7.5.8 ASSOCIATED COSTS

210. Section 7.2(b) of Schedule 1 to the RIN requires JEN to state whether the costs associated with JEN's initiative have been recovered under other schemes.

211. The associated costs for the development of the GESS Feasibility and Concept Design Study are not:

- recoverable under any other jurisdictional incentive scheme,

- recoverable under any other Commonwealth or State Government scheme, and
- included in the forecast capital or operating expenditure approved in the 2011-15 Distribution Determination or recovered under any other incentive scheme in that determination.

7.5.9 FORGONE REVENUE ASSUMPTIONS AND / OR ESTIMATES

212. Section 7.2(c) of Schedule 1 to the RIN requires JEN to explain any assumptions and/or estimates used in the calculation of forgone revenue, demonstrating the reasonableness of those assumptions and/or estimates in calculating forgone revenue, including the reasons for JEN's decision to adjust or not to adjust for other factors and the basis for any such adjustments.

213. The GESS Feasibility and Concept Design Study is limited to a desktop analysis of the technology as a peak demand management tool. Therefore, JEN does not seek to recover forgone revenue resulting from the GESS Feasibility and Concept Design Study for the 2015 Regulatory Year.

214. As such, section 7.2(c) of Schedule 1 to the RIN is not applicable.

7.6 DEMAND MANAGEMENT INNOVATION ALLOWANCE

215. Section 7.3 of Schedule 1 to the RIN requires JEN to state the total amount of the DMIA spent in the Relevant Regulatory Year and explain how it was calculated.

216. The actual costs incurred in the 2015 Regulatory Year for four projects were $94,494 as set out in Excel template 23 (DMIS – DMIA) Appendix B (Attachment 1-1 of this response to the RIN).

217. The project cost (materials, internal labour and external labour) is tracked in JEN's accounting systems.