Regulatory Investment Test for Distribution

DRAFT PROJECT ASSESSMENT REPORT

Charleville 66kV Voltage Management

This document describes the identified need for investment at Charleville, including the preferred option to address the identified need.

Consultation Period Starts: 26 July 2018
Consultation Period Closes: 7 September 2018

Disclaimer

While care was taken in preparation of the information in this Draft Project Assessment Report, and it is provided in good faith, Ergon Energy Corporation Limited accepts no responsibility or liability for any loss or damage that may be incurred by any person acting in reliance on this information or assumptions drawn from it. This document has been prepared for the purpose of inviting information, comment and discussion from interested parties. The document has been prepared using information provided by a number of third parties. It contains assumptions regarding, among other things, economic growth and load forecasts which may or may not prove to be correct. All information should be independently verified to the extent possible before assessing any investment proposal.
Executive Summary

Ergon Energy Corporation Limited (Ergon Energy) is responsible (under its Distribution Authority) for electricity supply to the Charleville, Quilpie and Cunnamulla area in south west Queensland.

Charleville is located in the Maranoa area of the South West Region of Ergon Energy’s Network. The Charleville area is supplied via a single 276km 66kV sub-transmission Feeder from T83 Roma Bulk Supply Point and customers in Quilpie and Cunnamulla are supplied via separate 200km long 66kV feeders from Charleville. Distribution supply from Charleville and Cunnamulla is at 11kV for urban, and 22kV and 19.1kV SWER for more rural customers. Supply from Quilpie zone substation is exclusively 11kV with extensive 19.1kV SWER networks. Charleville substation contains 1 x 66/11kV transformer, 1 x 66/22kV transformer, and also a 22/11kV transformer to link the 22kV and 11kV busbars and hence provide backup for each of the 66kV transformers. The Charleville zone substation contains a SVC which is connected to its 11kV bus. The SVC is set up to control the 66kV bus voltage and has a range of 7MVar inductive to 10MVar capacitive.

The Charleville SVC is approaching the end of its design life and it is recommended for replacement on the basis of its age and reliability in 2019. The SVC performs the function of maintaining stable voltages at both high and low load times. At low load times, without the SVC in service, significant voltage rise would occur on the Charleville area network. Similarly, without the SVC’s capacitive support, voltage would become low during high load periods. The SVC also provides some Negative Phase Sequence (NPS) correction to address voltage balance issues associated with SWER networks. If the Charleville SVC fails, inductors and capacitors are manually switched. This switching however creates transients on the network, is difficult to manage, and also relies on some plant which is also approaching end of life. At peak load times, without the SVC in service, some loads may also need to be shed in order to maintain a suitable voltage.

Ergon Energy published a Non-Network Options Report relating to the above described network constraints on 17 January 2018. Three submissions were received by the closing date of 16 April 2018.

One of these submissions was essentially the same as the preferred internal option given in the Non-Network Options Report and was deemed to be invalid on the grounds that it did not represent an alternative non-network solution. Although this submission was removed from the analysis in this report, the submission provider would have the opportunity to tender for the project if the analysis suggests that a network solution is the preferred option.

Three potentially feasible options have been investigated:

1. **Option A**: 10Mvar STATCOM (a 5Mvar STATCOM connected to each of the 11kV and 22kV buses) – Internal Option
2. **Option B**: 10Mvar STATCOM (a 5Mvar STATCOM connected to each of the 11kV and 22kV buses) with optional 2.8MW of embedded generation - External Submission Provider
3. **Option C**: 10MW solar farm (a 5MW solar farm connection to each of the 11kV and 22kV buses) and battery storage - External Submission Provider

This is a Draft Project Assessment Report, where Ergon Energy provides both technical and economic information about possible solutions. Ergon Energy’s preferred solution is Option A: 10Mvar STATCOM (a 5Mvar STATCOM connected to each of the 11kV and 22kV buses).

For further information and inquiries please refer to the “Regulatory Investment Test for Distribution (RIT-D) Partner Portal”.

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1. **Introduction**

This Draft Project Assessment Report has been prepared by Ergon Energy in accordance with the requirements of clause 5.17.4(i) of the National Electricity Rules (NER).

This report represents the second stage of the consultation process in relation to the application of the Regulatory Investment Test for Distribution (RIT-D) on potential credible options to address the identified need in the distribution network that supplies the Charleville, Quilpie and Cunnamulla areas.

On 17 January 2018, Ergon Energy published the first stage of the RIT-D, which was the release of the Non-Network Options Report. This report sought information from Registered Participants and Interested Parties regarding alternative potential credible options, or variants to the potential credible options presented in that report. In response to the Non-Network Options Report, Ergon Energy received three submissions.

This report:
- Provides background information on the network capability limitations of the distribution network supplying the Charleville, Quilpie and Cunnamulla areas.
- Identifies the need which Ergon Energy is seeking to address, together with the assumptions used in identifying and quantifying that need.
- Summarises and provides commentary on the submission(s) received on the Non-Network Options Report.
- Describes the credible options that are considered in this RIT-D assessment.
- Quantifies costs and classes of material market benefits for each of the credible options.
- Describes the methods used in quantifying each class of market benefit.
- Provides details of classes of market benefits that are not considered material to this RIT-D assessment, and provides explanations to why these classes of market benefits are not considered material.
- Provides the results of Net Present Value (NPV) analysis of each credible option and accompanying explanatory statements regarding the results.
- Identifies the proposed preferred option, including detailed characteristics, estimated commissioning date, indicative costs, and noting that it satisfies the RIT-D.
- Provides contact details for queries on this RIT-D.

In preparing this RIT-D, Ergon Energy is required to consider reasonable future scenarios. With respect to major customer loads and generation, Ergon Energy has, in good faith, included as much detail as possible while maintaining necessary customer confidentiality. Potential large future connections that Ergon Energy is aware of are in different stages of progress and are subject to change (including outcomes where none or all proceed). These and other customer activity can occur over the consultation period and may change the timing and/or scope of any proposed solutions.

All submissions and queries should be lodged to Ergon Energy’s “Regulatory Investment Test for Distribution (RIT-D) Partner Portal”. Submissions in writing are due by **31 August 2018**. The portal is available at:


For further information and inquiries please refer to the “Regulatory Investment Test for Distribution (RIT-D) Partner Portal”.
2. Background

2.1 Geographic Region

The geographic region covered by this RIT-D is Charleville, Quilpie and Cunnamulla towns and surrounding rural areas in south west Queensland. Charleville is located in the Maranoa area of the South West Region of Ergon Energy’s Network. The Charleville area is supplied via a single 276km 66kV sub-transmission Feeder from T83 Roma Bulk Supply Point and customers in Quilpie and Cunnamulla are supplied via separate 200km long 66kV feeders from Charleville. Distribution supply from Charleville and Cunnamulla is at 11kV for urban, and 22kV and 19.1kV SWER for more rural customers. Supply from Quilpie zone substation is exclusively 11kV with extensive 19.1kV SWER networks. Charleville substation contains 1 x 66/11kV transformer, 1 x 66/22kV transformer, and also a 22/11kV transformer to link the 22kV and 11kV busbars and hence provide backup for each of the 66kV transformers. The Charleville zone substation contains a SVC which is connected to its 11kV bus. The SVC is set up to control the 66kV bus voltage and has a range of 7MVAR inductive to 10MVAR capacitive. The figures below show the subtransmission infrastructure in the area and the location of Charleville substation.

Figure 1 – Charleville Subtransmission System
2.2 Charleville Supply System

As described above, the Charleville area is supplied via a single 276km 66kV sub-transmission feeder from T83 Roma Bulk Supply Point and customers in Quilpie and Cunnamulla are supplied via separate 200km long 66kV feeders from Charleville. Distribution supply from Charleville and Cunnamulla is at 11kV for urban, and 22kV and 19.1kV SWER for more rural customers. Supply from Quilpie zone substation is exclusively 11kV with extensive 19.1kV SWER networks. Charleville substation contains 1 x 66/11kV transformer, 1 x 66/22kV transformer, and also a 22/11kV transformer to link the 22kV and 11kV busbars and hence provide backup for each of the 66kV transformers. The Charleville zone substation contains a SVC which is connected to its 11kV bus. The SVC is set up to control the 66kV bus voltage and has a range of 7MVAR inductive to 10MVAR capacitive.

2.3 Existing Charleville SVC

The Charleville SVC is a critical asset approaching the end of its design life and it is recommended for replacement on the basis of its age and reliability in 2019. The SVC performs the function of maintaining stable voltages at both high and low load times. At low load times, without the SVC in service, significant voltage rise would occur on the Charleville area network. Similarly, without the SVC's capacitive support, voltage would become low during high load periods. The SVC also provides some Negative Phase Sequence (NPS) correction to address voltage balance issues associated with SWER networks. If the Charleville SVC fails, inductors and capacitors are manually switched. This switching however creates transients on the network, is difficult to manage, and also relies on some plant which is also approaching end of life. At peak load times, without the SVC in service, some loads may also need to be shed in order to maintain a suitable voltage.

SVC failure may lead to voltage compliance issues, customer complaints, loss of revenue and operational constraints in the south west Queensland distribution network. Sub-transmission and
distribution voltage levels may not be controlled within statutory limits, and the network will be at risk of over-voltages and under-voltages. Some load shedding is likely to occur either due to the voltage being excessively high or too low for the customers depending on the system load at the time.

The south west Queensland distribution network is characterised by relatively low fault levels with unacceptable voltage swings if large blocks of discrete capacitors or reactors are switched in and out for VAR compensation, hence the reason why a high reliability dynamic reactive compensator is necessary for voltage support.

2.3.1 Charleville SVC Operational Challenges

There are a number of operational challenges at Charleville substation associated with voltage control in the event that the SVC is out of service. This presents safety, voltage compliance and reliability risks. The SVC is critical to the provision of ongoing voltage/VAR support, and to meet Ergon Energy’s corporate strategic objectives. Without reactive compensation, 66kV supply at Charleville and the far south western Queensland suffers from poor voltage regulation. It may be noted that although no customer minutes have been recorded against SVC outages, there remains a potential for outages due to increasing loads and either low or high voltages on the network which can lead to unwanted tripping of loads by protection or operator intervention. During SVC outages, a significant amount of time is involved in maintaining volts on the 66kV busbar through reactor or capacitor switching and taps changing. The process is complex, slow and takes hours to manage by adjusting 66kV Roma bus volts and, on some occasions, even requesting Powerlink to lower the 132kV volts at Tarong and removing capacitor banks from service at Chinchilla. Despite these measures, the system voltage at Cunnamulla has become critically high on some occasions.

2.3.2 Charleville SVC Insufficient Reactive Power Capability

The existing SVC has a total capacitive range of 10MVAR and a total inductive range of 7MVAR. Of the 10MVAR capacitive range, only 7.6MVAR is available for steady state correction with the remaining 2.4MVAR reserved for dynamic/transient response. Similarly, for the 7MVAR inductive range, only 4.6MVAR is available for steady state correction with the remaining 2.4MVAR reserved for dynamic/transient response. The existing SVC is regularly hitting its steady state capacitive and inductive limits and any changes in the network which will increase peak load or decrease the minimum load could drive the need to increase the size of the SVC replacement.

There are significant SWER schemes emanating from these remote townships, particularly Quilpie with a very extensive SWER scheme generating significant reactive VARs under light load. Under light load, reactive VARs need to be continuously absorbed by the SVC to prevent system over voltages which would lead to unwanted VAR flows back from Charleville to Roma via the 66kV transmission line.

There is significant amount of MEGU (Micro Embedded Generation Unit) installations on the Charleville area network and this is expected to continue to grow (see below). Large customers in the area are also exploring opportunities to reduce their load with onsite generation. A number of larger megawatt scale solar proponents have also expressed interest in constructing solar farms at Charleville. The lowest loads are now seen during the middle of the day, during months with more mild weather conditions. In short it is expected that low load periods will continue to decline putting additional pressure on inductive compensation.
Figure 3 – PV/MEGU Connections in the Charleville Region

Charleville System MEGU

Installed Capacity

- Pv Panel Kw
- Pv Capacity Kw

Date Range:
- 23/01/2009 to 26/05/2016

Graph showing the installed capacity of Charleville System MEGU from 2009 to 2016.
3. Key Assumptions in Relation to Identified Need

Below is a summary of key assumptions that have been made when the identified need has been analysed and quantified.

It is recognised that the below assumptions may prove to have various levels of correctness, and they merely represent a 'best endeavours' approach to predict the future identified need.

3.1 Forecast Load Growth

The Ergon Energy Substation Investment Forecasting Tool (SIFT) predicts generally flat load growth within the area of interest (CHAR, QUIL and CUNN zone substations) which was deemed to be the most likely scenario. To model this level of network load, an entire year (2016) of half-hourly load data was selected to represent an 'average' year. According to SIFT, 2016 represented a 50% Probability of Exceedance demand and closely matches the substation demand forecasts in the 2018 model.

It was decided that a High Demand Growth scenario was also reasonable although less likely than the flat growth scenario described above. This was modelled by scaling the 2016 load data by a positive growth rate. The growth rate and probability of occurrence of each scenario are given in Table 1 below.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Probability</th>
<th>Growth Rate per annum</th>
</tr>
</thead>
<tbody>
<tr>
<td>High Demand Growth</td>
<td>0.2</td>
<td>2.00%</td>
</tr>
<tr>
<td>No Demand Growth</td>
<td>0.8</td>
<td>0.00%</td>
</tr>
</tbody>
</table>

3.2 Forecast Load Degradation

Unrestricted growth in Micro Embedded Generation Units (MEGU), such as residential Photovoltaics (PV), within the substation distribution areas leads to an erosion of network demand during the day. There is an existing customer base for this region of approximately 4930 customers and within this there is approximately 2.5MW of installed effective MEGU capacity (70% efficiency of existing connected system capacity). A further 5.1MW of solar generation capacity is a possible scenario based on a 70% maximum penetration, 70% average solar diversity and existing average system sizes. This was deemed to be the High MEGU Growth scenario.

A Low MEGU Growth scenario was also modelled which was based on the official 5 year Ergon Energy MEGU (combined) low forecast extrapolated out to the study period of 20 years. This led to an additional 3.6MW of solar generation capacity.

Each MEGU growth scenario was given an equal probability of occurrence. These assumptions are summarised in Table 2 below.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Probability</th>
<th>Additional MEGU Capacity in Year 20</th>
</tr>
</thead>
<tbody>
<tr>
<td>High MEGU Growth</td>
<td>0.5</td>
<td>5.1MW</td>
</tr>
<tr>
<td>Low MEGU Growth</td>
<td>0.5</td>
<td>3.6MW</td>
</tr>
</tbody>
</table>
3.3 Network Reliability Performance

Performance figures given in 3.1 and 3.2 were used to calculate the market benefits resulting from changes in involuntary load shedding (see Section 7.1.1).

3.3.1 Roma – Charleville 66kV Feeder Reliability Performance

Reliability performance of the ROMA – CHAR 66kV feeder that supplies CHAR, QUIL and CUNN is presented in Table 3 below. Outage rates are based on statistical analysis of similarly constructed overhead lines running in similar areas in the Ergon Energy network.

Table 3 – Reliability Performance – Roma-Charleville 66kV Feeder

<table>
<thead>
<tr>
<th>Element</th>
<th>Average No of Sustained Outages/Year</th>
<th>Average Duration/Outage</th>
<th>Average Outage Duration/Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Roma - Charleville 66kV Feeder</td>
<td>0.678</td>
<td>8h</td>
<td>5h 42 min</td>
</tr>
</tbody>
</table>

- Sustained Outage: >1 min. duration. Only sustained outages count towards value of customer reliability.

3.3.2 CHAR, QUIL and CUNN Substation Reliability Performance

Statistical analysis of historic outage rates across all Ergon Energy zone substations gives the rate of an outage to any MV bus as 0.0254 per year\(^1\) with an average restoration time of 1.06 hours.

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\(^1\) Considering sustained outages only.
4. Summary of Submissions

On 17 January 2018, Ergon Energy published the Non-Network Options Report providing details on the identified need to replace the SVC at Charleville. This report sought information from Registered Participants, AEMO and Interested Parties regarding alternative potential credible options or variants to the potential credible options presented by Ergon Energy.

In response to the Non-Network Options Report, Ergon Energy received three submissions from non-network service providers by 16 April 2018, which was the closing date for submissions to the Non-Network Options Report.

These three submissions were:

1. 10Mvar STATCOM (a 5Mvar STATCOM connected to each of the 11kV and 22kV buses) with optional 2.8MW of embedded generation.
2. 10MW solar farm (a 5MW solar farm connection to each of the 11kV and 22kV buses) and battery storage.
3. 12Mvar STATCOM (a 6Mvar STATCOM connected to each of the 11kV and 22kV buses)

Submissions 1 and 2 are composed of a STATCOM (or PV inverter functioning like a STATCOM) with a generation component and are substantially different to the Ergon Energy preferred network solution of a STATCOM alone. These options are considered to be valid, non-network alternatives to the preferred network solution.

Submission 3 is a STATCOM solution with no added alternate component and is essentially the same as the Ergon Energy preferred network solution. As such, it does not represent an alternative non-network solution. However, the submission provider would be given the opportunity to tender for the project if the analysis suggests that a network solution is the preferred solution.
5. Non-Network Solutions Considered

The two valid submissions Ergon Energy received to the Non-Network Options Report have been investigated and assessed, as detailed in the following section.

5.1 10Mvar STATCOM with optional 2.8MW of embedded generation – External Submission Provider

This submission is composed of a STATCOM component:

- 10Mvar STATCOM system (expanded to 15Mvar in year 5), modularised in separate containers of 2.5Mvar capacity each.
- Split into two separate 5Mvar STATCOMs, connected to the 11kV and 22kV buses respectively, although with the flexibility to be connected at more optimal locations within the network if required.
- The system is easily expandable by adding additional containers if required in the future. The cost analysis of this proposal includes two additional containers in year 5 to provide 15Mvar total reactive power capability.

Optional embedded generation components:

- 2MW gas generator configured for network support connected within the distribution network.
- 0.8MW cogeneration, hybrid generator connected at a large customer site and configured for network support.

Optional ancillary service:

- A controllable, 1MW / 1.5MWh thermal storage load installed at a large customer site for the purpose of network voltage / var management during light load periods.

The cost of this option is $20.5M (without optional generation) or $25.7M (inclusive of 2.8MW of generation) in NPV².

This option is named Option B in this report.

5.2 10MW solar farm and battery storage – External Submission Provider

This submission is composed of a PV inverter (functioning like a STATCOM) component:

- 10MW solar farm composed of two separate 5MW solar farms, connected to the 11kV and 22kV buses respectively.
- Each solar farm connection will have 8.25MVA PV inverters capable of generating ±6.5Mvar of reactive power at maximum real power output of 5MW.
- PV inverters will have ‘Q at night’ capability to allow 60% of inverter capacity to be used for reactive power support at night.

A battery component:

- Two separate 2.5Mvar battery inverters connected to the 11kV and 22kV buses respectively.

² Assuming a Weighted Average Cost Of Capital (WACC) of 7% as per the financial figures provided in the submission.
- Batteries sized to allow load shifting of excess generation as well as potential to supply the 11kV and 22kV buses (for approximately 2 to 4 hours) during an outage to the 66kV bus at CHAR.

Optional STATCOM:
- Scope to include two separate STATCOMs, connected to the 11kV and 22kV buses respectively, if required, to meet the STATCOM performance specifications.

The cost of this option is $798,000 per annum under a 20 year contract or $8.86M in NPV (assuming a 6.4% WACC).

This option is labelled as **Option C** in this report.
6. Credible Options Included in this RIT-D

Details of the three credible options that have been investigated to address the identified need at Charleville are presented in the following sections.

6.1 Option A: 10Mvar STATCOM - Internal Option

This is the preferred internal option composed of two separate 5Mvar STATCOMs, connected to the 11kV and 22kV buses respectively, and with the capability to be easily expanded up to 7.5Mvar units in the future.

This option will:

- Provide sufficient inductive and capacitive reactive power capability to manage network voltages at Charleville, Quilpie and Cunnamulla zone substations and surrounding distribution areas.
- Be able to be easily expanded to cater for future load growth and load degradation.
- Provide Negative Phase Sequence (NPS) correction to address voltage balance issues associated with SWER networks.
- Reduce voltage transients caused by inductor or capacitor switching and flicker caused by motor starting currents.

The estimated cost of this option is $5.5M. This is based on a capital cost of $4.6M and $0.9M for maintenance and operational costs.

It is expected that this option is able to be built, commissioned, accepted by Ergon Energy, and fully operational by June 2020 which is the required deadline given in the Non-Network Options Report.

6.2 Option B: 10Mvar STATCOM with optional 2.8MW of embedded generation – External Submission Provider

This option includes:

- 10Mvar STATCOM with optional 2.8MW of embedded generation (as described in Section 5.1).

This option will:

- Provide sufficient inductive and capacitive reactive power capability to manage network voltages at Charleville, Quilpie and Cunnamulla zone substations and surrounding distribution areas.
- Be able to be easily expanded to cater for future load growth and load degradation.
- Provide Negative Phase Sequence (NPS) correction to address voltage balance issues associated with SWER networks.
- Reduce voltage transients caused by inductor or capacitor switching and flicker caused by motor starting currents.
- Provides on optional 2.8MW of embedded generation that could be used to supply load at risk during an outage at CHAR.

Important things to note:

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Note that the Non-Network Options Report gave the internal option cost of $13.5M. However this figure is inclusive of internal costs to extend the yard and 22kV switchboard at CHAR as well as any other works required to enable connection of the new STATCOM and overheads. These internal costs were removed so as to allow direct comparison with the costs of other options.
The cost analysis of this proposal includes two additional containers in year 5 to provide 15Mvar total reactive power capability.

The cost of this option is $20.5M (without optional generation) or $25.7M (inclusive of 2.8MW of generation) in NPV\(^4\).

It is expected that this option is able to be built, commissioned, accepted by Ergon Energy, and fully operational by June 2020 which is the required deadline given in the Non-Network Options Report.

### 6.3 Option C: 10MW solar farm and battery storage – External Submission Provider

This option includes:

- 10MW solar farm with battery storage (as described in Section 5.2).

This option will:

- Provide sufficient inductive and capacitive reactive power capability to manage network voltages at Charleville, Quilpie and Cunnamulla zone substations and surrounding distribution areas.
- Be able to be easily expanded to cater for future load growth and load degradation.
- Provide Negative Phase Sequence (NPS) correction to address voltage balance issues associated with SWER networks.
- Reduce voltage transients caused by inductor or capacitor switching and flicker caused by motor starting currents.
- Provides potential to supply the 11kV and 22kV buses (for approximately 2 to 4 hours) during an outage to the 66kV bus at CHAR.
- Potentially reduce the amount of network losses by having a generation source (the solar farm / batteries) at CHAR.

Important things to note:

The cost of this option is $798,000 per annum under a 20 year contract or $8.86M in NPV (assuming a 6.4% WACC).

It is expected that this option is able to be built, commissioned, accepted by Ergon Energy, and fully operational by June 2020 which is the required deadline given in the Non-Network Options Report.

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\(^4\) Assuming a Weighted Average Cost Of Capital (WACC) of 7% as per the financial figures provided in the submission.
7. Market Modelling

The RIT-D requires market benefits to be calculated by comparing the ‘state of the world’ in the base case (the preferred Ergon Energy internal option, Option A) with the ‘state of the world’ with each of the credible options in place. The ‘state of the world’ means a reasonable and mutually consistent description of all the relevant supply and demand characteristics that may affect the calculation of the market benefits over the period of assessment. **Rather than using the wording ‘state of the world’, Ergon Energy has used the wording ‘state of the system’ in this RIT-D assessment.** The uncertainty associated with the future state of the system is addressed by considering a number of reasonable scenarios (see Section 3. ). The RIT-D assessment has been undertaken over a 20-year period.

7.1 Classes of Market Benefits Considered & Quantified

The purpose of the RIT-D is to identify the option that maximises the present value of net market benefits to all those who produce, consume and transport electricity in the National Electricity Market (NEM).

In order to measure the increase in net market benefit, Ergon Energy has analysed the classes of market benefits required to be considered by the RIT-D.

The following classes of market benefits are considered material, and have been included in this RIT-D assessment:

- Changes in involuntary load shedding.
- Changes in network losses

7.1.1 Changes in Involuntary Load Shedding

All credible options included in this RIT-D assessment will provide similar levels of reactive power capability; adequate to meet current and future requirements at CHAR. For each option, there is negligible risk of running out of capacitive VAR support during high load conditions which might necessitate customer load shedding. Therefore there is no need to quantify these market benefits. However, each option has varying capabilities to supply load during outages at CHAR e.g. by embedded generation and so the impact of changes in involuntary load shedding was calculated for this scenario.

This was done by determining, through network modelling, the average Load at Risk (LAR) for outages on each bus at CHAR (11kV, 22kV and 66kV). This was done for both the High Demand Growth and No Demand Growth scenarios described in Section 3.1 . The hours at risk per annum for each contingency scenario were calculated assuming the reliability parameters in Section 3.3 and multiplied with the LAR to find the energy at risk per annum. These figures were weighted by the expected probability of each scenario and converted to a dollar value\(^5\) which reflects the customer financial consequence of the unserved energy. The net reduction of this dollar value (as compared to the Base Case option) is represented as a market benefit and is presented in Table 4.

\(^5\) This study used a Value of Customer Reliability figure of $39.71/kWh based on VALUE OF CUSTOMER RELIABILITY – APPLICATION GUIDE (2014), Section 1.2 - Queensland VCR excluding direct connects.
Table 4 – Market Benefit of Changes in Involuntary Load Shedding

<table>
<thead>
<tr>
<th>Market Benefit</th>
<th>Option A: 10Mvar STATCOM – Base Case</th>
<th>Option B: 10Mvar STATCOM - no embedded generation</th>
<th>Option B: 10Mvar STATCOM - 2.8MW of embedded generation</th>
<th>Option C: 10MW solar farm and battery storage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Changes in involuntary load shedding and customer interruptions caused by network outages</td>
<td>$0</td>
<td>$0</td>
<td>$4,959,557</td>
<td>$2,856,931</td>
</tr>
</tbody>
</table>

### 7.1.2 Changes in Network Losses

Market benefits associated with the change in network losses within the Ergon Energy network have been quantified by a direct calculation of the likely MWh impact on the losses for each year of the modelling horizon. These MWh figures have been multiplied by the value of those losses, as determined by the annual volume weighted average spot price of electricity for QLD 2017/18 ($76/MWh).

It was assumed that the only option that will have a material impact in network losses is Option C - 10MW solar farm and battery storage. It was assumed that the embedded generation component of Option B would mainly be used for peak lopping and not be run for long enough during the year to have a significant effect.

The cost of energy losses for each scenario (shown in Table 5) were calculated for Option C then probability weighted and compared to the Base Case. The total cost of energy losses for Option C is shown as a market benefit in Table 6. It can be seen that this is actually a negative benefit indicating that network losses increased with this option. This was shown in the modelling where, in the High MEGU Growth scenarios, real power was flowing back to ROMA on the 66kV ROMA-CHAR line for significant portions of the year.

This modelling assumed a typical generation profile for the solar farm and due to insufficient information, did not model the battery charging / discharging regime. The submission received from the external provider stated that the batteries might be used to store ‘excess’ solar generation to be exported at a later time. Discharging the batteries during high load times would likely reduce the amount of network losses during this time however the majority of the solar farm generation would still be exporting to the grid during daylight hours. It is expected that modelling the battery charging / discharging regime is unnecessary since it would improve the model accuracy only marginally but would add far greater complexity to the analysis.
### Table 5 – Changes in Network Losses Scenario Probability

<table>
<thead>
<tr>
<th>Load Growth Scenario</th>
<th>Load Growth Scenario</th>
<th>Probability</th>
</tr>
</thead>
<tbody>
<tr>
<td>High Demand Growth</td>
<td>High MEGU Growth</td>
<td>0.1</td>
</tr>
<tr>
<td>High Demand Growth</td>
<td>Low MEGU Growth</td>
<td>0.1</td>
</tr>
<tr>
<td>Low Demand Growth</td>
<td>High MEGU Growth</td>
<td>0.4</td>
</tr>
<tr>
<td>Low Demand Growth</td>
<td>Low MEGU Growth</td>
<td>0.4</td>
</tr>
</tbody>
</table>

### Table 6 – Market Benefit of Changes in Network Losses

<table>
<thead>
<tr>
<th>Market Benefit</th>
<th>Option A: 10Mvar STATCOM – Base Case</th>
<th>Option B: 10Mvar STATCOM - no embedded generation</th>
<th>Option B: 10Mvar STATCOM - 2.8MW of embedded generation</th>
<th>Option C: 10MW solar farm and battery storage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Changes in Network Losses</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>-$1,091,083</td>
</tr>
</tbody>
</table>
7.2 Classes of Market Benefits not Expected to be Material

The following classes of market benefits are not considered to be material for this RIT-D assessment:

- Changes in voluntary load curtailment
- Changes in costs to other parties
- Changes in timing of expenditure
- Changes in load transfer capability
- Option value

7.2.1 Changes in Voluntary Load Curtailment

Because none of the credible options include any voluntary load curtailment, and because there are no customers on voluntary load curtailment agreements in the distribution areas of Charleville, Quilpie or Cunnamulla substations at present, any market benefits associated with changes in voluntary load curtailment have not been considered.

7.2.2 Changes in Costs to Other Parties

Ergon Energy does not anticipate that any of the credible options included in this RIT-D assessment will affect costs incurred by other parties.

7.2.3 Changes in Timing of Expenditure

None of the credible options included in this RIT-D assessment is expected to affect the timing of other distribution investments for unrelated identified needs.

7.2.4 Changes in Load Transfer Capability

Neither of the credible options will have a materially different impact upon the load transfer capability between CHAR, QUIL, CUNN or ROMA substations.

7.2.5 Option Value

The AER’s view is that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change, and the credible options considered by the RIT-D proponent are sufficiently flexible to respond to that change. Each option is assumed to be installed and commissioned by June 2020 which is effectively an irreversible investment. In this context each option will have the same Option Value and so it is not required to be quantified.

7.3 Quantification of Costs for each Credible Option

The capital and operational costs for each credible option considered in this RIT-D assessment are summarised in Table 7. Note that these costs are exclusive of the internal costs to extend the yard and 22kV switchboard at CHAR as well as any other works required to enable connection of the new STATCOM and overheads.

---

<table>
<thead>
<tr>
<th>Option</th>
<th>Capital Cost (Excl. Ergon Overheads)</th>
<th>Operational Cost (Excl. Ergon Overheads)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Option A</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10Mvar STATCOM - Internal Option</td>
<td>$4.6M</td>
<td>$80K per annum or $0.9M in NPV</td>
</tr>
<tr>
<td><strong>Option B</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10Mvar STATCOM with optional 2.8MW of embedded generation – External Submission Provider</td>
<td>$20.5M (without optional generation) or $25.7M (inclusive of 2.8MW of generation)</td>
<td>Included in Capital Costs</td>
</tr>
<tr>
<td><strong>Option C</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10MW solar farm and battery storage – External Submission Provider</td>
<td>$798,000 per annum under a 20 year contract or $8.86M in NPV</td>
<td>Operational costs included in the annual fee</td>
</tr>
</tbody>
</table>
8. Financial Analysis

8.1 Net Present Value

Net Present Values of the three credible options are presented in Table 8 below. The NPV analysis demonstrates that Option A has the lowest Net Present Cost.

Table 8 – Net Present Value Analysis

<table>
<thead>
<tr>
<th></th>
<th>Option A: 10Mvar STATCOM – Base Case</th>
<th>Option B: 10Mvar STATCOM - no embedded generation</th>
<th>Option B: 10Mvar STATCOM - 2.8MW of embedded generation</th>
<th>Option C: 10MW solar farm and battery storage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Costs</td>
<td>$4,600,000</td>
<td>$20,496,716</td>
<td>$25,696,716</td>
<td>$8,863,044</td>
</tr>
<tr>
<td>Direct cost (External works only)</td>
<td>$888,526</td>
<td>-$</td>
<td>-$</td>
<td>-$</td>
</tr>
<tr>
<td>Maintenance / Operation</td>
<td>$5,488,526</td>
<td>$20,496,716</td>
<td>$25,696,716</td>
<td>$8,863,044</td>
</tr>
<tr>
<td>Total costs</td>
<td>$8,863,044</td>
<td>$20,496,716</td>
<td>$25,696,716</td>
<td>$8,863,044</td>
</tr>
<tr>
<td>Market Benefits</td>
<td>Changes in involuntary load shedding and customer interruptions caused by network outages</td>
<td>$4,959,557</td>
<td>$2,856,931</td>
<td>$1,091,083</td>
</tr>
<tr>
<td>Changes in electrical energy losses</td>
<td>$4,959,557</td>
<td>$2,856,931</td>
<td>$1,091,083</td>
<td>-$</td>
</tr>
<tr>
<td>Total Market Benefit</td>
<td>$4,959,557</td>
<td>$2,856,931</td>
<td>$1,091,083</td>
<td>$1,765,848</td>
</tr>
<tr>
<td>Benefit Less Costs</td>
<td>-$5,488,526</td>
<td>-$20,496,716</td>
<td>-$25,696,716</td>
<td>-$7,097,196</td>
</tr>
<tr>
<td>Ranking</td>
<td>1</td>
<td>3</td>
<td>4</td>
<td>2</td>
</tr>
</tbody>
</table>
9. Proposed Preferred Option

The previous section has presented the results of the NPV analysis conducted for this RIT-D assessment.

The NER requires the Draft Project Assessment Report to include the preferred option under the RIT-D. This should be the option with the greatest net market benefit and which is therefore expected to maximise the present value of the net market benefits to all those who produce, consume and transport electricity in the market.

This RIT-D assessment has clearly demonstrated that Option A maximises the present value of net market benefits under all reasonable scenarios considered. The preferred option is therefore Option A: 10Mvar STATCOM - Internal Option.

This option satisfies the RIT-D.

The total cost, inclusive of operating costs and market benefits, is estimated at $5.49M in present value terms. Note that this cost is exclusive of the internal costs to extend the yard and 22kV switchboard at CHAR as well as any other works required to enable connection of the new STATCOM and overheads.

The technical characteristics of the preferred solution are presented below:

*Install two separate 5Mvar STATCOMs, connected to the 11kV and 22kV buses respectively, and with the capability to be easily expanded up to 7.5Mvar units in the future.*
10. Submissions and Next Steps

10.1 Request for Submissions

Ergon Energy invites written submissions on this report from registered participants and interested parties.

Ergon Energy will not be legally bound in any way or otherwise obligated to any person who may receive this RIT-D report or to any person who may submit a proposal. At no time will Ergon Energy be liable for any costs incurred by a proponent in the assessment of this RIT-D report, any site visits, obtainment of further information from Ergon Energy or the preparation by a proponent of a proposal to address the identified need specified in this RIT-D report.

All submissions and queries should be lodged to Ergon Energy’s “Regulatory Investment Test for Distribution (RIT-D) Partner Portal”. Submissions in writing are due by 31 August 2018. The portal is available at:


10.2 Next Steps

Following Ergon Energy’s consideration of the submissions, the preferred option, and a summary of and commentary on any submissions received in response to this report, will be included as part of the Final Project Assessment Report. The Final Project Assessment Report represents the final stage of the consultation process in relation to the application of the RIT-D.


Ergon Energy will use its reasonable endeavours to publish the Final Project Assessment Report by the above date. This may however not be achievable due to changing power system conditions or other circumstances beyond the control of Ergon Energy.

At the conclusion of the consultation process, Ergon Energy intends to take steps to progress the recommended solution(s) to ensure any statutory non-compliance is addressed and undertake appropriately justified network reliability improvement(s), as necessary.