Regulatory Test - Consultation and draft recommendation report

Proposed Upgrade to Boyne Island Substation

19 March 2014

Ergon Energy Corporation Limited

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1. EXECUTIVE SUMMARY

Ergon Energy Corporation Limited (Ergon Energy) is responsible (under its Distribution Authority) for electricity supply to the wider Gladstone area in central Queensland. We have identified emerging limitations in the electricity distribution network supplying the Boyne Island and Tannum Sands areas south of Gladstone. The loads on Ergon Energy's zone substation and 11kV network in the Boyne Island/Tannum Sands area have progressively increased such that augmentation is required if reliable supply is to be maintained.

The Boyne Island/Tannum Sands area is presently supplied by the Boyne Residential 66/11kV zone substation. This substation is supplied from a single 66kV line which connects to the Gladstone South-Awoonga 66kV line.

The load on the Boyne Residential 66/11kV zone substation has exceeded the N-1 substation capacity by 3.7MVA and the level of exceedance is forecast to increase into the future. A transformer contingency may result in customer load shedding of up to 3.7MVA at present with this increasing to be up to 8.6MVA by 2020.

Due to only having a single incoming 66kV supply line Boyne Residential substation does not have N-1 66kV supply capacity and a fault anywhere on the 30km of 66kV supply line will result in a total outage to the Boyne Residential zone substation. This represents the loss of up to 13.7MVA of load at present with this increasing to be up to 18.6MVA by 2020.

To reduce the risk of customer supply outages to the Boyne Island/Tannum Sands area Ergon Energy needs an additional minimum of 10MVA capacity at 11kV to be provided to this area. This size has been matched to expected load requirements within Ergon Energy's typical 10 year planning horizon.

In order to significantly reduce the risk of losing electricity supply to customers in the Boyne Island/Tannum Sands area corrective action should be completed before summer 2015/16. A decision about the selected option is required by April 2014 if any option involving significant construction is to be completed by November 2015.

Ergon Energy published a Request for Information relating to this emerging network constraint on 11 December 2013. Four submissions were received by the closing date of 12 February 2014.

Five feasible solutions to the emerging network constraint have been identified:

Option 1	Upgrade the existing Boyne Residential Substation with 2 x 20MVA transformers, and an additional 66kV line
Option 2	External Party A – 10MVA of diesel generation
Option 3	External Party B – Concentrated photovoltatic dish system, deep cycle batteries with diesel backup
Option 4	External Party C - 10MVA of diesel generation
Option 5	External Party D – 10MVA of generation – Ergon Energy owned and run

This is now a Consultation and Draft Recommendation where Ergon Energy provides both economic and technical information about possible solutions, and our recommended solution, being Option 1, to upgrade the existing Boyne Residential Substation and construct an additional 66kV line by 2016/17.

Submissions in writing are due by 16 April 2014 and should be lodged to:

Attention: Network Planning and Strategy

Email: regulatory.tests@ergon.com.au

Updated information will be provided on our web site:

http://www.ergon.com.au/community--and--our-network/network-management/regulatory-test-consultations

For further information and inquiries please submit to the email address above.

2. INTRODUCTION

Ergon Energy has identified emerging limitations in the electricity distribution network supplying the Boyne Island & Tannum Sands area south of Gladstone in central Queensland.

When a distribution network service provider proposes to establish a new large distribution network asset to address such limitations, it is required under the National Electricity Rules (NER) clause 5.6.2(f) to consult with affected Registered Participants, AEMO and Interested Parties on possible options to address the limitations. These options may include but are not limited to demand side options, generation options, and market network service provider options.

Under clause 5.6.2(g) of the NER the consultation must include an economic cost effectiveness analysis of possible options to identify options that satisfy the Australian Energy Regulator's (AER) Regulatory Test, while meeting the technical requirements of Schedule 5.1 of the NER.

The Consultation and Draft Recommendation in this Paper is based on:

- the assessment that a reliable power supply is not able to be maintained in the Boyne Island / Tannum Sands area.
- the Request for Information consultation undertaken by Ergon Energy to identify potential solutions to address the emerging distribution network limitations; and
- an analysis of feasible options in accordance with the AER's Regulatory Test.

This project has been considered under the reliability limb of the Regulatory Test as the service standards linked to the technical requirements of Schedule 5.1 of the NER and Ergon Energy's licence conditions are unable to be met, as detailed in Section 5 of this report.

This project was included in the Ergon Energy Network Management Plan 2012/13 to 2016/17.

3. BACKGROUND & REASONS AUGMENTATION IS REQUIRED

3.1. Background

If technical limits of the distribution system will be exceeded and the rectification options are likely to exceed $10M, Ergon Energy is required under the NER[1] to notify Registered Participants,[2] AEMO and Interested Parties[3] within the time required for corrective action and meet the following regulatory requirements:

- Consult with Registered Participants, AEMO and Interested Parties regarding possible solutions that may include local generation, demand side management and market network service provider options[4].
- Demonstrate proper consideration of various scenarios, including reasonable forecasts of electricity demand, efficient operating costs, avoidable costs, costs of ancillary services and the ability of alternative options to satisfy emerging network limitations under these scenarios.
- Ensure the recommended solution meets reliability requirements while minimising the present value of costs when compared to alternative solutions[5].

Ergon Energy is responsible for electricity supply to the wider Gladstone area (under its Distribution Authority) and has identified emerging limitations in the electricity network supplying the Boyne Island and Tannum Sands area south of Gladstone. The load on Ergon Energy's supply network in this area has progressively increased such that augmentation is required if reliable supply is to be maintained.

3.2. Purpose of this "Consultation and Draft Recommendation"

The purpose of this Consultation and Draft Recommendation is to:

- Provide information about the existing distribution network in the Boyne Island/Tannum Sands area.
- Provide information about emerging distribution network limitations and the expected time by which action must be taken to maintain the reliability of the distribution system.
- Provide information about options identified and considered.
- Explain the process (including approach and assumptions) and the AER's Regulatory Test used to evaluate alternative solutions, including distribution options.
- Recommend Ergon Energy's preferred solution.

[1] Clause 5.6.2(f)
[2] As defined in the NER
[3] As defined in the NER
[4] NER clause 5.6.2(f)
[5] In accordance with the AER's Regulatory Test Version 3, November 2007

4. EXISTING SUPPLY SYSTEM TO THE BOYNE ISLAND/TANNUM SANDS AREA

4.1. Geographic Region

The geographic region covered by this Consultation and Draft Recommendation report is broadly described as the Boyne Island/Tannum Sands area as shown on the map below.

4.2. Existing Supply System

The Boyne Island and Tannum Sands area is supplied by the Boyne Residential 66/11kV zone substation (the diagram in 4.1 shows the location of this zone substation), which presently supplies over 4500 customers.

Boyne Residential Zone Substation comprises of two 10 MVA 66/11 kV transformers. The output capacity of each transformer is limited to 10 MVA due to the 11 kV transformer cables. The 2013 recorded maximum demand on Boyne Residential zone substation was 13.7MVA with demand forecast to grow at an average of 4% pa over the next 10yrs. Therefore the peak load on Boyne Residential sub exceeds the N-1 transformer capacity by 3.7MVA, with this amount increasing into the future.

The substation has a single 66 kV incoming supply feeder which is connected via a hard tee to the Gladstone South to Awoonga 66kV line. This line has a summer day capacity of 19MVA. Therefore Boyne Residential substation does not have N-1 66kV supply capacity and a fault anywhere on the 30km of 66kV supply line will result in a total outage to the Boyne Residential zone substation.

Table 1 below provides the recorded and forecast demands on Boyne Residential zone substation.

5. EMERGING NETWORK LIMITATIONS

5.1. Applied Service Standards

The service standards that are applicable to a consideration of supply constraints affecting this area of study are summarised below:

- Ergon Energy's subtransmission network has a risk based planning model that takes into consideration the deterministic "N-1" security of supply criteria, the Value of Customer Reliability (VCR) and Safety Net. Safety Net will protect customers from high impact – low probability events where an upper limit is set for a customer outage consequence for a single contingency event on Ergon's network. The Safety Net outage magnitude & duration thresholds have been developed to align with the System Average Interruption Duration Indices (SAIDI) consequence that scores the maximum consequence score in Ergon's Network Risk Analysis.
- The distribution network planning criteria threshold so that a 50PoE load should not exceed 0.75 x Normal Cyclic Capacity (NCC) rating of the feeder.

5.2. Limitations of the Existing Network

A load history and forecast for the Boyne Residential substation load, is shown in Table 1 below.

TABLE 1 – Boyne Residential Supply Substation Load History & Forecast

Substation	Maximum Annual Demand (MVA)											
	Actual Load		Forecast Load									
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Boyne Res Sub 50% POE	**12.5**	**13.7**	***15.5***	***16.2***	***16.9***	***17.7***	***17.8***	***18.4***	***18.6***	***19.5***	***19.9***	***20.6***
Boyne Res Sub 10% POE			***16.6***	***17.3***	***18.4***	***19.0***	***19.3***	***19.9***	***20.4***	***21.0***	***21.6***	***22.6***

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It is clear from the load data in Table 1 that:-

From the supply system information given in 4.2 above and the demand data from Table 1 the following issues are defined:-

1. The load on Boyne Residential zone substation has exceeded the N-1 capacity of the substation. Based on forecast demands by 2020 the demand on Boyne Residential zone substation will exceed the N-1 capacity of the substation by 8.6MVA.
2. Based on the demand forecast the load on Boyne Residential zone substation will exceed the total transformer output capacity in 2020. This will result in overloaded plant or the need for loadshedding in system normal network arrangements (note: the determination of emerging plant overloads under system normal conditions, is carried out using the 10% POE forecast).
3. Loss from service of the 66kV supply line to Boyne Residential zone substation will result in a total outage to the Boyne Residential zone substation. If the line fault is located on either the Gladstone South to Boyne Res Tee line section or the Awoonga to Boyne Res Tee line section then the Boyne Residential substation supply could be restored in about 30 minutes via network switching. If the line fault is located on the section of line from the Tee to Boyne Residential substation then the supply to the substation cannot be restored until the line is repaired, which could take 6-8 hrs.

5.3. Timeframes for Taking Corrective Action

In order to significantly reduce the risk of losing electricity supply to customers in the Boyne Island/Tannum Sands area corrective action should be completed before summer 2015/16.

A decision about the selected option is required by April 2014 if any option involving significant construction is to be completed by November 2015.

5.4. Known Future Network and Generation Development

(i.e. projects that have been approved and are firm to proceed)

Ergon Energy is not aware of any other network augmentations or generation developments in the Boyne Island area that could relieve the emerging network limitations described in section 5.0 above.

6. OPTIONS CONSIDERED

6.1. Consultation Summary

During its planning process, Ergon Energy identified that action would be required to address an anticipated distribution network limitation related to supply to the Boyne Island and Tannum Sands area.

On 11 December 2013 Ergon Energy released a Request for Information providing details on the emerging network limitations in the Boyne Island/Tannum Sands area. That paper sought information from Registered Participants, AEMO and Interested Parties regarding potential solutions to address the anticipated limitations.

Ergon Energy received four submissions by 12 February 2014, being the closing date for submissions to the Request for Information paper.

6.2. Non-Network Options Identified

In order to satisfy the Regulatory Test, Ergon Energy sought to identify demand side options or demand side/network combinations that address the network limitations at a lower total present value that the proposed network solution.

To be considered an alternative demand side option, the proposed solution was required to:

- Have the capacity to defer the proposed network solution by reducing demand below the identified constraint limits;
- Cost less than the savings gained by deferring or removing the proposed network solution; and
- Meet all applied service standard requirements.

This analysis identified no feasible demand side alternative options.

6.3. Distribution Options Identified

In addition to the consultation process to identify possible non-network solutions, Ergon Energy carried out studies to determine the most appropriate distribution network solutions. It was considered that a “do nothing” approach was unacceptable. Five feasible corrective solutions were identified, details of which are contained in the following Section 7.

7. FEASIBLE SOLUTIONS

This section provides an overview of the feasible solutions identified, with full details of the financial analysis contained in Section 7.4. Figures shown below do not include Ergon Energy overheads.

7.1. Option 1 – Augment the existing Boyne Residential Substation by 2017

Option 1 – Augment Boyne Residential Substation		
Date Req'd	*Augmentation*	*Capital Cost*[6]
November 2015	Install new 66kV line and uprate existing 66kV line between Boyne Tee and Boyne Residential	$ 6,843,886
January 2017	Replace existing transformers with 2 x 20MVA 66/11kV and upgrade cables and required secondary systems (SCADA), and additional 11kV feeder bay	$ 9,424,442
November 2015	Commission additional 11kV feeder to Tannum Sands area	$ 853,595

This option involves delivery of the following work:-

- Install a new 66kV line section from Boyne Residential Tee to Boyne Residential Zone Substation
- Raise the line clearance on the existing Boyne Residential Tee to Boyne Residential Zone Substation to 75˚C allowable conductor temperature as required.
- Remove existing 7.5/10MVA 66/11kV transformers and install two new 20MVA 66/11kV transformers and upgrade associated cables.
- Install a 66kV CB in each transformer bay and bring both 66kV feeder bays in to line with the zone substation standards
- Install an additional 11kV indoor feeder bay
- Upgrade SCADA systems
- Conduct a detailed analysis of the distribution network to identify locations where the fault current is expected to exceed the rating of the expulsing drop out fuses (8kA) and replace these with high rupture capacity fuses (HRC)

The Option 1 programme of works as proposed will have the following benefits:

- Secure supply to Boyne Residential / Tannum Sands area
- Allows for network expansion in future

Disadvantages of this option are:

- Limited number of 11kV feeders can be installed
- Capital cost

[6] Does not include overheads

7.2. Option 2 – External Party A – Diesel Generation

Option 2 – External Party A			
Date Req'd	*Augmentation*	*Capital Cost*[7]	*Operational Cost*
June 2015	Purchase land – 690m^2 approx	$ 207,000	
June 2015	Construct approximately 1.3km of overhead 11kV line the potential generation site[8], along with required switches	$ 249,000	
November 2015 – March 2025	Engage external contractor to provide 10MVA of diesel generation in the Boyne Residential area		$1.9M per year capacity, plus energy charges as indicated below
June 2016	Workshop repair of the two existing Boyne Residential transformers (aged asset requirement)	$ 326,000	
2025/26	Network works as described in Option 1	$ 23,600,000[9]	

This option involves delivery of the following work:-

- Purchase of land for the proposed generation site (approximate size, 30x23m, or 690m^2) at a cost of $300 per sqm
- Required network connections (assumption – 1.3km of 11kV line, plus switches)
- Engage External Party A to install five diesel generation units for a total of 10MVA for $1.9M per annum for ten years, with an energy charge of $203.83 per MWh
- Use generation during contingency periods, and to relieve distribution constraints as required (anticipated energy- actual energy may be higher or lower depending on network conditions):

	2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**
MWh per annum	53.2	90.5	134.1	184.9	243.3	310.3	386.9	474.2
Cost of energy per annum ($000s)	11	18	27	38	50	63	79	97

- Once the contract period had expired, the installation of the network works as described in Option 1

The Option 2 programme of works as proposed will have the following benefits:

- Minimal upfront capital cost

Disadvantages of this option are:

- Lack of new distribution capacity

[7] Does not include overheads
[8] Assumed. Actual location may differ, which may result in a different required line length.
[9] Includes inflation of 3.73% p.a.

7.3. Option 3 – External Party B – Concentrated Photovoltaic Dish System with Battery Storage and Diesel Backup

Option 3 – External Party B			
Date Req'd	*Augmentation*	*Capital Cost*[10]	*Operational Cost*
June 2015	Purchase land – 113,312m^2 approx	$ 16,997,000	
June 2015	Construct approximately 1.3km of overhead 11kV line the potential generation site[11], along with required switches	$ 249,000	
November 2015 – March 2025	Engage external contractor to provide 10MVA hybrid CPV/Deep Cycle Batteries/Generation		$3.0M per year capacity, plus energy charges as indicated below
June 2016	Workshop repair of the two existing Boyne Residential transformers (aged asset requirement)	$ 326,000	
2025/26	Network works as described in Option 1	$ 23,600,000[12]	

This option involves delivery of the following work:-

- Purchase of land for the proposed solution site (approximate size, 113,312m^2) at a cost of $80 per sqm[13]
- Required network connections (assumption – 1.3km of 11kV line, plus switches)
- Engage External Party B to install 7MW of concentrated photovoltaic (CPV) modules, with 50MWh of deep cycle battery bank, and 10x1MW generators as backup for a total of 10MVA for $3.0M per annum for ten years, with an energy charge of $180.00 per MWh
- Use solution during contingency periods, and to relieve distribution constraints as required (anticipated energy- actual energy may be higher or lower depending on network conditions):

	2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**
MWh per annum	53.2	90.5	134.1	184.9	243.3	310.3	386.9	474.2
Cost of energy per annum ($000s)	10	16	24	33	44	56	70	85

- Once the contract period had expired, the installation of the network works as described in Option 1

The Option 3 programme of works as proposed will have the following benefits:

- Innovative system

Disadvantages of this option are:

- High Cost
- Lack of new distribution capacity
- Large area of land required – 11 hectares (113,213m^2)

[10] Does not include overheads
[11] Assumed. Actual location may differ, which may result in a different required line length.
[12] Includes inflation of 3.73% p.a.
[13] It is assumed that due to the large land size, the per sqm price will be lower than a small site

7.4. Option 4 – External Party C – Diesel Generation

Option 4 – External Party C			
Date Req'd	*Augmentation*	*Capital Cost*[14]	*Operational Cost*
June 2015	Purchase land – 500m^2 approx	$ 150,000	
June 2015	Construct approximately 1.3km of overhead 11kV line the potential generation site[15], along with required switches	$ 249,000	
November 2015 – March 2025	Engage external contractor to provide 10MVA of generation		$1.2M per year capacity, plus energy charges as indicated below
June 2016	Workshop repair of the two existing Boyne Residential transformers (aged asset requirement)	$ 326,000	
2025/26	Network works as described in Option 1	$ 23,600,000[16]	

This option involves delivery of the following work:-

- Purchase of land for the proposed solution site (approximate size, 500m^2) at a cost of $300 per sqm
- Required network connections (assumption – 1.3km of 11kV line, plus switches)
- Engage External Party C to deliver 10MVA of generation for $1.2M per annum for ten years, with an energy charge of $350.00 per MWh, 2 hour dispatch minimum
- Use solution during contingency periods, and to relieve distribution constraints as required (anticipated energy- actual energy may be higher or lower depending on network conditions):

	2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**
MWh per annum (incl. minimum)	26	26	77	114	158	209	267	334
Cost of energy per annum ($000s)	9	9	27	40	55	73	94	117

- Once the contract period had expired, the installation of the network works as described in Option 1

The Option 4 programme of works as proposed will have the following benefits:

- Minimal upfront capital cost

Disadvantages of this option are:

- Lack of new distribution capacity

7.5. Option 5 – External Party D – Diesel Generation, Ergon Energy Owned

Option 5 – External Party D		
Date Req'd	*Augmentation*	*Capital Cost*[17]
June 2015	Purchase land – 1750m^2 approx	$ 150,000

[14] Does not include overheads
[15] Assumed. Actual location may differ, which may result in a different required line length.
[16] Includes inflation of 3.73% p.a.
[17] Does not include overheads

June 2015	Construct approximately 1.3km of overhead 11kV line the potential generation site[18], along with required switches	$ 249,000
November 2015	Engage External Party D to construct 10MVA diesel generation plant	$ 5,227,000
June 2016	Workshop repair of the two existing Boyne Residential transformers (aged asset requirement)	$ 326,000
2025/26	Network works as described in Option 1	$ 23,600,000[19]

This option involves delivery of the following work:-

- Purchase of land for the proposed generation site (approximate size, 50x35m, or 1750m^2) at a cost of $300 per sqm
- Required network connections (assumption – 1.3km of 11kV line, plus switches)
- Engage External Party D to design and construction a 11MVA diesel standby generation solution for a total cost of $5,227,000 excluding GST.
- Use generation during contingency periods, and to relieve distribution constraints as required (anticipated energy- actual energy may be higher or lower depending on network conditions):

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
MWh per annum	1.8	1.9	53.2	90.5	134.1	184.9	243.3	310.3	386.9	474.2
Litres of petrol	767	808	22,470	38,209	56,636	78,093	102,762	131,053	163,430	200,298

- After ten years, the installation of the network works as described in Option 1

The Option 5 programme of works as proposed will have the following benefits:

- Allows flexible timing of network solution

Disadvantages of this option are:

- Lack of new distribution capacity

[18] Assumed. Actual location may differ, which may result in a different required line length.
[19] Includes inflation of 3.73% p.a.

8. FINANCIAL ANALYSIS & RESULTS

8.1. Format and Inputs to Analysis

8.1.1 Regulatory Test Requirements

The requirements for the comparison of options to address an identified network limitation are contained in the Regulatory Test (version 3, November 2007) prescribed by the AER.

The Regulatory Test requires that, for reliability augmentations, the recommended option be the one that **"minimises the costs of meeting those requirements, compared with alternative option/s in a majority of reasonable scenarios"**. To satisfy the Regulatory Test, the proposed augmentation must achieve the lowest cost in the majority of (but not necessarily all) credible scenarios.

The Regulatory Test contains guidelines for the methodology to be used to identify the lowest cost option. Information to be considered includes construction, operating and maintenance costs and the costs of complying with existing and anticipated laws and regulations. The Regulatory Test specifically excludes indirect costs and costs that cannot be measured in terms of financial transactions in the electricity market.

8.1.2 Inputs to Analysis

A solution to address the future supply requirements for the Boyne Island/ Tannum Sands area as outlined in this document is required to satisfy reliability requirements linked to Schedule 5.1 of the NER and the requirements of the Queensland *Electricity Act 1994*.

According to the AER's Regulatory Test, this means that the costs of all options must be compared, and the least cost solution is considered to satisfy the Regulatory Test. The results of this evaluation, carried out using a discounted cash flow model to determine the present value costs of the various options, are shown in section 8.2.2.

The cost to implement the network augmentations outlined in section 7 has been estimated by Ergon Energy. Sensitivity studies have been carried out using variations in capital cost estimates of plus or minus 20%. The operating and maintenance costs have been derived as a fixed proportion of capital cost. As a result, a variation in capital costs would be equivalent to separately varying the operating and maintenance cost.

The financial analysis considers all foreseeable cost impacts of the proposed network augmentations to market participants as defined by the regulatory process. [Estimated savings in the cost of network losses have been excluded from the analysis because they were not found to differ significantly between the five feasible options over the twenty year study period.]

8.2. Financial Analysis

The economic analysis undertaken considered the present value of cost of alternative options over the twenty year period from 2012/13 to 2032/33.

8.2.1 Present Value Analysis

Financial analysis was carried out to calculate and compare the Present Value (PV) of the costs of each option under the range of assumed scenarios.

A twenty year analysis period was selected as an appropriate period for financial analysis. A discount rate of 9.99% was selected as a relevant commercial discount rate.

The Base Case (Scenario A) was developed to represent the most likely market scenario.

Market scenarios were formulated to test the robustness of the analysis to variations in load forecast, capital costs and the discount rate. As required by the Regulatory Test, the lower boundary of the sensitivity testing was the regulated cost of capital.

Under the Regulatory Test, it is the ranking of options which is important, rather than the actual present value results. This is because the Regulatory Test requires the recommended option to have the lowest present value cost compared with alternative projects.

The following table is a summary of the economic analysis. It shows the present value cost of each alternative and identifies the best ranked option, for the range of scenarios considered.

The summary shows that **Option 1 – Augment Boyne Residential has the lowest present value under all scenarios [except Scenario High Discount Rate where it is tied with External Party D]**.

8.2.2 Summary of Economic Analysis

Commercial Outcomes excl Overheads ($M)	Network Solution	External Party A	External Party B	External Party C	External Party D
Present Cost of Capex	$13.09	$8.87	$16.75	$8.82	$13.54
Present Cost of Opex	$3.76	$16.19	$22.52	$12.31	$5.59
Present Value of Benefits	$1.84	$3.04	$3.95	$3.03	$3.11
NET PRESENT VALUE / (COST)	-$15.01	-$22.02	-$35.32	-$18.10	-$16.02
Value compared to best Option	$0.00	-$7.01	-$20.31	-$3.09	-$1.01

Sensitivity Analysis excl Overheads ($M)		Network Solution	External Party A	External Party B	External Party C	External Party D
Scenario - Base Case		-$15.01	-$22.02	-$35.32	-$18.10	-$16.02
		1	4	5	3	2
Scenario - Escalation Opex - High	+20%	-$15.76	-$25.26	-$39.83	-$20.56	-$17.14
		1	4	5	3	2
Scenario - Escalation Opex -Low	-20%	-$14.26	-$18.78	-$30.82	-$15.63	-$14.90
		1	4	5	3	2
Scenario - Discount Rate - High	12.00%	-$14.29	-$19.32	-$31.88	-$15.86	-$14.29
		1	4	5	3	1
Scenario - Discount Rate - Low [REG]	9.72%	-$15.10	-$22.42	-$35.82	-$18.42	-$16.27
		1	4	5	3	2
Scenario - Increased Capital costs	+20%	-$17.63	-$23.80	-$38.67	-$19.86	-$18.73
		1	4	5	3	2
Scenario - Decreased Capital costs	-20%	-$12.39	-$20.25	-$31.97	-$16.33	-$13.31
		1	4	5	3	en
Scenario - Commercial Benefits	-20%	-$15.38	-$22.63	-$36.11	-$18.70	-$16.64
		1	4	5	3	2

8.3. Discussion of Results

The following conclusions have been drawn from the analysis presented in this report:

- There is no acceptable ‘do nothing’ option. If the emerging network constraints are not addressed by 2016, Ergon Energy will not be able to meet its security criteria in the event of a subtransmission failure to Boyne Residential substation, resulting in certain loss of supply to network users.

- Economic analysis carried out in accordance with the Regulatory Test has identified that proposed augmentation described in Option 1, is the least cost solution over the twenty year period of analysis in all scenarios considered [except Scenario High Discount Rate].

- Sensitivity testing showed that the analysis is robust to variations in capital costs and the selected discount rate.

- As Option 1 is the lowest cost option in all scenarios except Scenario High Discount Rate, it is considered to satisfy the AER’s Regulatory Test.

9. DRAFT RECOMMENDATION

Based on the conclusions drawn from the analysis in sections 7 and 7.4 above, it is recommended that Ergon Energy proceeds with Option 1 to:-

- **Augment Boyne Residential Substation by 2017.**

Technical details relevant to the proposed new large distribution asset are contained in section 7.1.

10. CONSULTATION

In accordance with the NER[20], Ergon Energy invites submissions from affected Registered Participants, AEMO and Interested Parties on this Consultation Paper and Draft Recommendation.

10.1. Timetable for Submissions

Submissions in writing (electronic preferably) are due by **16 April 2014** and should be lodged to:

Attention: Network Planning and Strategy

Email: regulatory.tests@ergon.com.au

10.2. Assessment and Decision Timetable

Ergon Energy intends to carry out the following process to assess what action should be taken to address the identified distribution network limitations:

Step 1	Request for (initial) Information - **Complete**.	Date Released: **11 December 2013**
Step 2	Submissions in response to the Request for Information - **Complete.**	Due Date: **12 February 2014**
Step 3	Review and analysis by Ergon Energy - **Complete**. This is likely to involve further consultation with proponents and additional data may be requested.	Anticipated to be completed by: **26 February 2014**
Step 4	Release of Ergon Energy's Consultation Paper and Draft Recommendation of solution which satisfies the Regulatory Test - **This document**.	Anticipated to be released by: **19 March 2014**
Step 5	Submissions in response to the Consultation Paper & Draft Recommendation.	Due Date: **16 April 2014**
Step 6	Release of Final Recommendation (including summary of submissions received).	Anticipated to be released by: **30 April 2014**
Ergon Energy reserves the right to revise this timetable at any time. The revised timetable will be made available on the Ergon Energy website http://www.ergon.com.au/community--and--our-network/network-management/regulatory-test-consultations		

Ergon Energy will use its reasonable endeavours to maintain the consultation program listed above. However this program may alter due to changing power system conditions or other circumstances beyond the control of Ergon Energy. Updated information will be made available on our website: http://www.ergon.com.au/community--and--our-network/network-management/regulatory-test-consultations

The consultation timetable is driven by the need to make a decision by April 2014 if any option involving significant construction is to be in place by November 2015.

At the conclusion of the consultation process, Ergon Energy intends to take steps to progress the recommended solution to ensure system reliability is maintained.

[20] Clause 5.6.2(f)