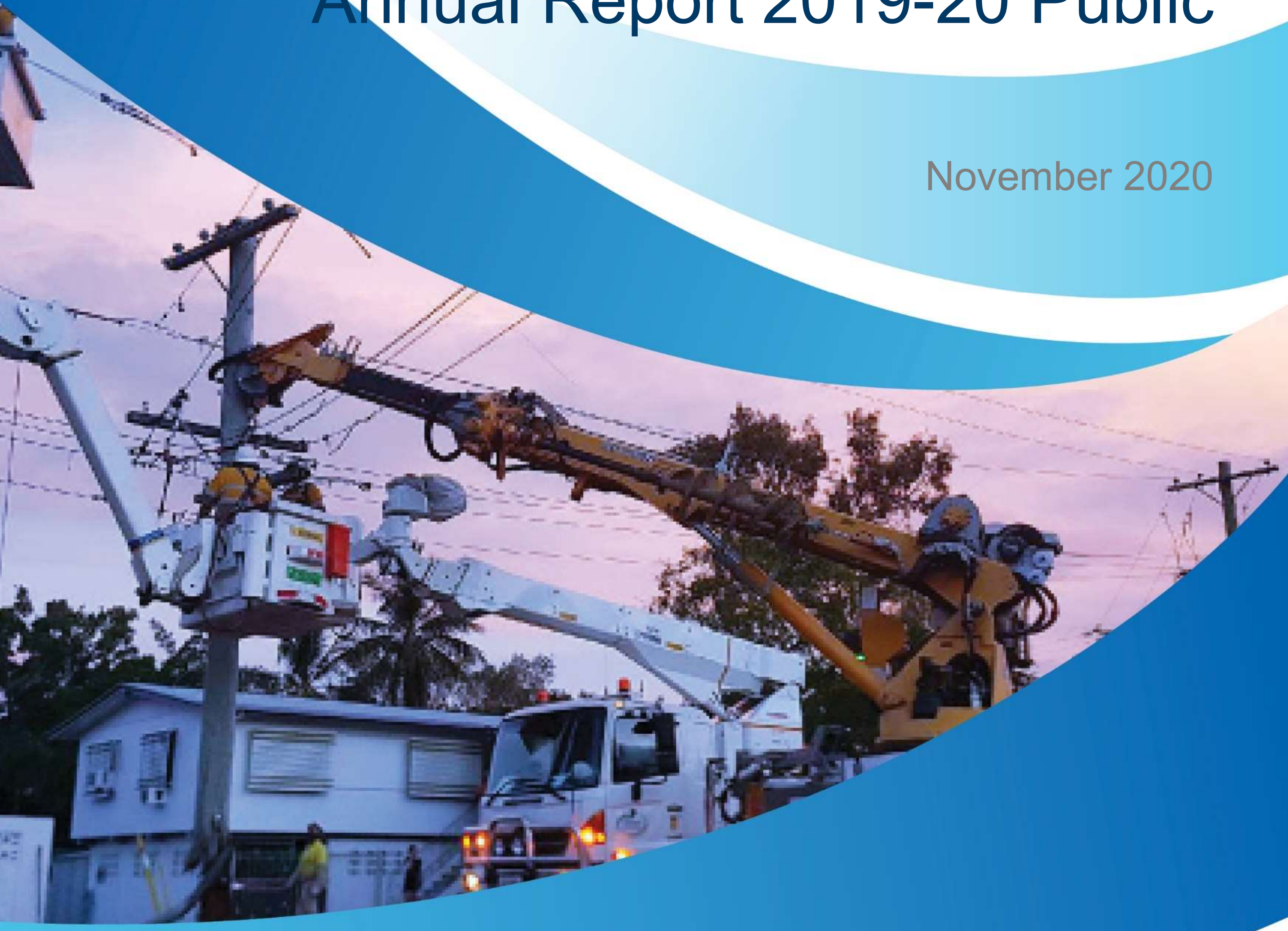
Ergon Energy Demand Management Incentive Scheme (DMIS) Annual Report 2019-20 Public

November 2020



ERGON. ENERGY NETWORK

Part of Energy Queensland

Contents

1. Introduction

1.1 Purpose of report

This report has been prepared in accordance with section 2.4 of the Demand Management Incentive Scheme (DMIS) applied to Ergon Energy by the Australian Energy Regulator (AER).

Under DMIS, Ergon Energy is required to submit a demand management compliance report to the AER, no later than 4 months after the end of the relevant regulatory year.

This report fulfils the reporting requirements of DMIS and provides information on **committed projects** (Part A) and **eligible projects** (Part B) and the **total financial incentive** assessed as being claimable under DMIS for the 2019/20 year.

The AER will use this report to determine the **total financial incentive** for 2019/20. Once approved, this incentive will be added to Ergon Energy's total annual revenue for 2021/22.

2. PART A – Committed Projects

2.1 Summary of outcomes from current committed projects

2.1.1 Cairns South Target Area

Project Summary	
Description of need	In 2019-20, Ergon Energy committed to a DM project to address 2.4MVA Load at Risk (LAR). The existing network supply (2GO1,2GO2 and 2GO3 interconnector mesh 22kV feeders) to the Gordonvale area does not meet the distribution feeder security criteria.
Volume of DM delivered during the year	2400kVA
Actual expenditure incurred for the year	[redacted] The actual expenditure is less than forecast, as the generation was not called upon, whereas forecast expenditure had allowed for a maximum of 30 hours during 2019-20.
Relevant net benefit	[redacted]

2.2 Summary of total incentives accrued from committed projects

Summary of Committed Projects									
Project	DM delivered (kVA)	PV costs ($m)	Net Benefits ($m)	DMIS incentive ($m)					
				2019-20	2020-21	2021-22	2022-23	2023-24	2024-25
Cairns South Target Area	2,400	[redacted]		0.112					
Total incentive accrued to projects				0.112					
1% of Annual Revenue incentive (assumption)				11.79					
Total incentive accrued (up to cap)				0.112					
Total incentive to be paid (total accrued with 2 year lag)						0.112			

3. PART B – Eligible Projects

3.1 Summary of eligible projects

Project	DM Targeted (kVA)	PV Costs ($m)	Net Benefit ($m)
Cairns South Target Area	2,400		
Townsville North West Target Area	1,000		
Emerald Target Area	±10 to ±20MVAR	Not available	Not available

3.2. Details of eligible projects

3.2.1. Cairns South Target Area

Project Summary	
Description of need	2.4MVA Load at Risk (LAR) The existing network supply (2GO1,2GO2 and 2GO3 interconnector mesh 22kV feeders) to the Gordonvale area does not meet the distribution feeder security criteria. These criteria specify that a radial feeder with effective ties to three or more feeders should be loaded to no more than 75% utilisation (i.e. Target Maximum Utilisation (TMU) of 75%) under system normal conditions at 50 PoE. On the loss of a feeder, closing the ties to other feeders, allows supply to be restored to the affected feeder without overloading the tie feeders. Note: As the identified need of this project is reliability corrective action, ‘do nothing’ has not been considered (refer to section 5.4).
Credible network option	Gordonvale property acquisition (WR1400633 @ $0.593M); and 2MPR 22kV augmentation (i.e. estimated project $3.4M) Base Case 2019/20

Identifying eligible projects		
Process followed	☐ RIT- D	☒ MPERS
Request for demand management solution issued	☐ RIT-D listed on website ☐ Notice sent to Demand Side Engagement Register ☐ Notice sent to other parties (enter date)	☒ Target Area on website advertised (17/7/2019) ☐ Request for Proposal (RFP) issued (N/A) ☒ Notice sent to Demand Side Engagement Register (17/7/2019) ☐ Notice sent to other parties (enter date)
Information contained in request	Not applicable	Refer to (link/ screen shot) Cairns South Advertised.JPG Cairns South Advertised NO1.JPG Cairns South Advertised No3.JPG Cairns South Advertised Deeral.JP Cairns South Advertised Mt Peter Cairns South Advertised Riverstor

Description of responses received			
	Response #1	Response #2	Response #3
Demand Management Project Description	Synchronised Generation	N/A	N/A
Deliverables	2400kVA	-	-
Cost	[redacted]	-	-
Assessment	Preferred Option	-	-
Likely next steps for eligible project			
☒ DM Contract	Contract signed with proponent. Contract commenced on 1 April and valid to 31 March 2022. This is now a committed project. See Attachment 1 for a copy of the contract.		
☐ DM Proposal			

DM Costs and DM Delivered by Eligible Project									
Cashflow analysis		**kVA requirements and contract summaries**						**PV of benefits (deferral value) ($)**	**Cumulative NPV**
Year	**Fin Year**	**kVA required**	**kVA delivered**	**kVA deficit**	**Cost ($)**	**$/kVA (avg)**	**PV of costs ($)**		
0	2019-20	2,400	2,400	0	[redacted]				
1	2020-21	2,400	2,400	0	[redacted]				
2	2021-22	2,400	2,400	0	[redacted]				
Cashflows/ discounted					[redacted]		[redacted]		

3.2.2 Townsville North West Target Area

Project Summary	
Description of need	1MVA Load at Risk (LAR) The existing network supply (DG-07, DG-10 and BO-10 11kV feeders) to the Bohle Plan area does not meet the distribution feeder security criteria. All three feeders operate above 75% Target Maximum Utilisation and have limited tie points to other feeders. During summer peak load conditions, it would not be possible to restore supply to all customers in the event of a sustained unplanned outage. Under this scenario there is a capacity shortfall of 1 MVA. The distribution feeder security criteria specify that a radial feeder with effective ties to three or more feeders should be loaded to no more than 75% utilisation (i.e. Target Maximum Utilisation (TMU) of 75%) under system normal conditions at 50 PoE. On the loss of a feeder, closing the ties to other feeders, allows supply to be restored to the affected feeder without overloading the tie feeders. Note: As the identified need of this project is reliability corrective action, ‘do nothing’ has not been considered (refer to section 5.4).
Credible network option	Construction of underground feeder tie between BO-10 and AL-26, estimated cost $1.45M. Base Case 2020/21.

Identifying eligible projects		
Process followed	☐ RIT- D	☒ MPERS
Request for demand management solution issued	☐ RIT-D listed on website ☐ Notice sent to Demand Side Engagement Register ☐ Notice sent to other parties (enter date)	☒ Target Area on website advertised (17/7/2019) ☐ Request for Proposal (RFP) issued (N/A) ☒ Notice sent to Demand Side Engagement Register (17/7/2019) ☐ Notice sent to other parties (enter date)
Information contained in request	Not applicable	Refer to (link/ screen shot) Map1.JPG Map2.JPG Map3.JPG

Description of responses received			
	Response #1	Response #2	Response #3
Demand Management Project Description	Embedded Generation via Commercial Battery Energy Storage System (BESS) to defer network option from 2020/21 to 2025/26.	N/A	N/A
Deliverables	1000kVA	-	-
Cost		-	-
Assessment	Preferred Option	-	-

Likely next steps for eligible project	
☒ DM Contract	Currently negotiating contract with proponent
☐ DM Proposal	

DM Costs and DM Delivered by Eligible Project

Cashflow analysis		kVA requirements and contract summaries						PV of benefits (deferral value) ($)	Cumulative NPV
Year	Fin Year	kVA required	kVA delivered	kVA deficit	Cost ($)	$/kVA (avg)	PV of costs ($)		
0	2020-21	1,000	1,000	0					
1	2021-22	1,000	1,000	0					
2	2022-23	1,000	1,000	0					
	2023-24	1,000	1,000	0					
	2024-25	1,000	1,000	0					

3.2.3 Emerald Target Area

Project Summary	
Description of need	**As per EOI**: The existing 66kV network does not have sufficient capability to supply the forecast increased load at Emerald under system normal conditions, and voltage constraints. VAR support is required to provide a minimum of ±10MVAR, with capability to be expanded up to a total of ±20MVAR, to cater for possible growth and changing voltage constraints beyond 2025. Note: As the identified need of this project is reliability corrective action, 'do nothing' has not been considered (refer to section 5.4).
Credible network option	**As per FPAR Option A:** Install 11MVAr of additional reactive compensation (via capacitor banks) at Emerald Zone Substation and upgrade the Blackwater – Emerald Feeder by 2019/20. Cost as per FPAR/EOI $6.5M Updated costs March 2020 Install capacitor banks (Project WR928870). Estimated cost is $6.765M. Base Case 2020/21.

Identifying eligible projects		
Process followed	☒ RIT- D	☐ MPERS
Request for demand management solution issued	☒ RIT-D listed on website ☒ Notice sent to Demand Side Engagement Register ☐ Notice sent to other parties (enter date)	☐ Target Area on website advertised ☐ Request for Proposal (RFP) issued ☐ Notice sent to Demand Side Engagement Register ☐ Notice sent to other parties (enter date)
Information contained in request	Refer to – NNOR – Emerald_RIT-D Non-Network Optio Closed 02/10/2015 DPAR - Emerald_RIT-D Draft Project Assessment I Closed 29/7/2016 FPAR – Emerald-FPAR Published 30/11/16 EOI - Emerald EOI Final.pdf Closed 21/03/2017 EOI – Findings – Emerald EOI Findings.pdf	NA

Description of responses received				
	Response #1	Response #2	Response #3	- Response #4
Submission				
Demand Management Project Description	Provide Reactive Network Support via 80MV Solar Farm	Solar PV MVAar and battery, delivering 6 MVAR of leading or lagging reactive power atop the 10MW rated real power.	Reactive Network Support; MVAr Export only	80MW Solar Farm with supply to net +/- 10MVAr of reactive support increasing annually
Deliverables	+/-10MVAr	10 MVar / 16.7 MVA inverter capacity & 10MW battery	10.5MVAr	+/-10MVAr
Cost outlined as per EOI		No Cost Provided		
Assessment	Preferred option Note: This proponent was first to get a connection agreement and therefore automatically became the preferred proponent.	-	-	-

Likely next steps for eligible project	
☒ DM Contract	Currently negotiating contract with proponent
☐ DM Proposal	

4. Demand Management Projects that have changed

4.1 Previously reported eligible or committed DM projects now deferred or not proceeding

None

4.2 Previously committed DM projects now superseded by network option

None

5. Additional Information

This section sets out additional information on how Ergon Energy has applied the Scheme.

5.1 Early application of DMIS

In June 2018, Ergon Energy applied to the AER for the early application of the DMIS prior to the start of the 2020-25 regulatory control period. This was accepted by the AER in December 2018 resulting in DMIS applying to Ergon Energy from 1 April 2019. The relevance of this date is that to be eligible for DMIS, a project must not have had expenditure committed by the distributor prior to this date. All demand management projects contained in this report are compliant with this requirement.

No **committed** or **eligible projects** were reported in 2018/19 and therefore this is the first compliance report submitted under DMIS.

5.2 Reporting requirements

The annual compliance report must include:

- information on **committed projects** (Part A), including details of:
  - volume of demand management delivered
  - an estimate of the realised benefits
  - total incentive to be claimed
- Information on **eligible projects** (Part B) identified as a preferred option, including details of:
  - present value of costs and benefits
  - description of responses to the request for demand management solutions
  - if the project is to proceed as a **committed project**, whether the project will occur via a **demand management contract** or via a **demand management proposal**
  - expected costs of delivering the demand management solution.
  - kVA per year of network demand able to be called upon, influenced, dispatched or controlled

- Any projects where a decision has been made to defer or not proceed with an **eligible project** that previously was reported to proceed as a **committed project**

- Any projects where a decision has been made to proceed with a network option to meet an identified need that previously was to proceed as a **committed project**.

5.3 Identifying eligible projects

As specified in section 2.2 of DMIS, a distributor must identify where a project is an efficient non-network option by completing at least one of the following processes:

- the AER's regulatory investment test for distribution (**RIT-D**); or
- the minimum project evaluation requirements (**MPERS**).

The RIT-D process, as outlined in AER – Final RIT-D application guidelines (2018), sets out comprehensive market engagement, assessment of credible network and non-network options and reporting requirements. Information on current and past RIT-D projects is available on the Ergon Energy website. In any given regulatory year, where an efficient non network option is identified as part of a RIT-D, this project will be added to the list of **eligible projects** in the demand management compliance report submitted to AER.

MPERS, as set out in 2.2.1 of DMIS, provides a simpler and streamlined set of requirements for market engagement, assessment of credible network and non-network options and reporting. Ergon Energy undertakes market engagement in accordance with **MPERS** either by publishing network limitations (Target Areas) online using incentive/rewards maps or inviting proponents to respond to a Request for Proposal (RFP). Refer to the Ergon Energy website for list of current Target Areas and for a list of past and current RFPs. In any given regulatory year, where an efficient non network option is identified during a **MPERS**, this project will be added to the list of **eligible** in the demand management compliance report submitted to the AER.

5.4 Determining efficiency of demand management projects

In order to assess the efficiency of demand management projects, a cost benefit analysis is undertaken. The cost-benefit assessment is based on **Net Present Value (NPV)** assessment of relevant costs and benefits of credible options.

For **eligible projects** identified by a **RIT-D** process, a comprehensive **NPV** analysis is undertaken, as set out in the AER – Final RIT-D application guidelines (2018).

For **eligible projects** identified by **MPERS**, a simpler NPV analysis is undertaken, as follows:

- network option costs and benefits include:
- expected capital cost of the preferred network option
- non-network option costs and benefits include:
- time value of money benefit associated with deferring the network option
- expected costs of delivering demand reductions

As outlined in 2.2(2) and further in 2.3(5) a demand management project is considered feasible where:

(a) it has a positive NPV when assessed against a base case of doing nothing; or

(b) for reliability corrective actions, the NPV of the demand management project is greater than the credible option with second highest net benefit.

Reliability corrective projects can be required to meet Safety Net target or Target Maximum Utilisation (TMU) criteria as outlined below.

5.5 Network Planning Criteria

Ergon Energy and Energex are issued a Distribution Authority by the Queensland Government's Department of Natural Resources, Mines and Energy (DNRME) (the Regulator), allowing them to supply electricity within their distribution area. Ergon Energy's Distribution Authority can be accessed by the following link:

https://www.dews.qld.gov.au/__data/assets/pdf_file/0004/219487/distribution-authority-d0199-ergon.pdf

Ergon Energy is required under its Distribution Authority, to adhere to the probabilistic planning approach where full consideration is given to the network risk at each location, including operational capability, plant condition and network meshing with load transfers. This approach is used to rank potential network investments for consideration against budget and resource levels.

Sub-Transmission and Sub/Zone-Station Planning Security Criteria – Service Safety Net Targets

While this approach provides an effective methodology for keeping costs low; high consequence-low probability events could still cause significant disruption to supply with potential customer hardship and/or significant community and economic disruption.

The Safety Net requirements outlined in the Distribution Authority address this issue by providing a set of security criteria that set an upper limit to the customer consequences (in terms of unsupplied load) for a credible contingency event by setting restoration targets at the time of an event. For further information on Service Safety Net requirements, refer to Schedule 3 of the Distribution Authority or Table 10, in section 6.4.2 of the DAPR.

A review of the network's sub-transmission feeders with zone and bulk supply substations against Safety Net requirements is performed annually. System contingency related capability is assessed against a 50% probability of exceedance (PoE) forecast load, availability load transfers, emergency cyclic capacity (ECC) ratings, non-network response, mobile plant, mobile generators and any short-term ratings of plant and equipment that are available.

Distribution Network Planning Security Criteria – Target Maximum Utilisation (TMU)

Target Maximum Utilisation (TMU) is used as a trigger for potential applications of non-network solutions or capacity improvements for the 11kV and 22kV network. The TMU for various areas are outlined below.

<u>CBD and Critical Loads</u>

Any feeder in a balanced three feeder mesh should be loaded to no more than 67% utilisation under system normal conditions at 50 PoE. Any feeder in a balanced two feeder mesh should be loaded to no more than 50% utilisation under system normal conditions at 50 PoE.

Mesh networks are more common in the Brisbane dense CBD areas where high reliability is critical and thus the loss of a single feeder should not affect supply.

<u>Urban Feeders</u>

What is referred to as an Urban Feeder in the security criteria is essentially a radial feeder, with ties to adjacent radial feeders. A radial feeder with effective ties to three or more feeders should be loaded to no more than 75% utilisation under system normal conditions at 50 PoE.

On the loss of a feeder, closing the ties to other feeders allows supply to be restored to the affected feeder without overloading the tie feeders.

<u>Rural Feeders</u>

For a point load that has no ties, or a rural radial feeder, the TMU will be capped at 90% at 50 PoE, unless the supply agreement specifically requires a different value.

5.6 Identifying committed projects

As outlined in 2.2.2 of DMIS, an eligible project becomes a committed project when either:

- Ergon Energy enters a demand management contract with another legal entity to procure the demand management required to deliver the preferred option; or
- Ergon Energy approve a demand management proposal for the distributor to provide itself the demand management required to deliver the preferred option.

6. Glossary

The terms in **bold** are defined below as they are used in the Demand Management Incentive Scheme regulation, dated December 2017. Please see scheme here.

Term	Definition
committed project	See clause 2.2.2(1)
demand management contract	See clause 2.2.2(2)
demand management proposal	See clause 2.2.2(3)
eligible project	See clause 2.2(1) An eligible project is a project that a distributor has identified in accordance with 2.2(4), as being an efficient non network option relating to demand management, but that has not had expenditure committed to it by the distributor before the first application of the scheme to the distributor in a distribution determination.
MPERS	minimum project evaluation requirements See clause 2.2.1
NPV	Net present value
RIT-D	Regulatory investment test for Distribution
total financial incentive	Means the sum of all project incentives accrued by a distributor in a regulatory year, capped (where applicable) at the amount set out in clause 2.5(2)