

# Application of Incentive Schemes

## 2020-25

January 2019



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## 1. Overview

We operate under an incentive-based regulatory framework where we are encouraged to continuously improve efficiency. A key feature of this framework is that the Australian Energy Regulator (AER) sets the maximum revenue that we can recover from our customers over the course of the regulatory control period. This encourages us to provide our services at a lower cost than forecast by the AER.

The National Electricity Rules (NER) also stipulate that the AER may, or must, develop a suite of incentive schemes to compliment the incentive-based regulatory framework. These include:

- a service target performance incentive scheme (STPIS)<sup>1</sup>, which encourages us to improve or maintain our service performance
- an efficiency benefit sharing scheme (EBSS)<sup>2</sup>, which encourages us to pursue operating expenditure (opex) efficiency improvements
- a demand management incentive scheme (DMIS)<sup>3</sup>, which encourages us to undertake efficient expenditure on relevant non-network options relating to demand management
- a demand management innovation allowance mechanism (DMIAM)<sup>4</sup>, which provides research and development funding for demand management projects
- a capital expenditure sharing scheme (CESS)<sup>5</sup>, which encourages us to pursue capital expenditure (capex) efficiency improvements, and
- a small-scale incentive scheme (SSIS)<sup>6</sup>.

In the Framework and Approach (F&A) paper for Energex and Ergon Energy for the 2020-25 regulatory control period, the AER proposed to apply each of these schemes with the exception of the SSIS which is yet to be developed.

We support the application of the incentive schemes as we consider that they align our incentives with the long-term interests of our customers. This ultimately promotes the National Electricity Objective. We only benefit under these incentive schemes if customers also benefit. With the exception of the recently developed DMIS, the schemes outlined above apply in the current regulatory control period.

We note that we are responding to incentives by outperforming our service performance targets in the current regulatory control period, projecting to underspend our capex and opex allowances and continuing to pursue demand management. As a result, Ergon Energy is entitled to revenue increments under the AER's CESS and EBSS for efficiencies achieved in the current 2015-20 regulatory control period. However, we are currently proposing, subject to the AER's acceptance of our Regulatory Proposal, to not claim the potential revenue adjustment associated with efficiency schemes in this Regulatory Proposal. In doing so, we believe we are presenting a balanced proposal focussed on our customer's key concerns of safety, affordability and security and sustainability. In the event the AER has any concerns with our Regulatory Proposal in its Draft Determination, we will reassess our approach to efficiency schemes to ensure our Revised Regulatory Proposal continues to provide a balanced approach in the long term interests of our customers

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<sup>1</sup> NER, CI 6.6.2

<sup>2</sup> NER, CI 6.5.8

<sup>3</sup> NER, CI 6.6.3

<sup>4</sup> NER, CI 6.6.3A

<sup>5</sup> NER, CI 6.5.8A

<sup>6</sup> NER, CI 6.6.4

This document sets out our proposed approach for each incentive scheme that is proposed to apply in the 2020-25 regulatory control period. This document should be read in conjunction with our Regulatory Proposal.

## **2. Capital expenditure sharing scheme**

### **2.1 Overview**

The CESS incentivises us to undertake efficient capex over the regulatory control period by providing financial rewards and penalties for efficiency gains and losses on capex, respectively. The AER's approved forecast capex is used as a proxy for efficient capex, and differences between forecast and actual capex approximate efficiency gains and losses. We share the efficiency gains and losses with customers.

The CESS aims to address the issue of declining incentives to pursue capex efficiency over the regulatory period. It provides us with the same reward or penalty in each year of the regulatory control period. In this way, we have a continuous incentive to pursue capex efficiency.

### **2.2 NER and Reset RIN requirements**

The CESS NER requirements are set out in clauses 6.3.2, 6.4.3, 6.4A, 6.5.8A, 6.8.1, 6.12.1 and Schedule 6.1.3.

In general, these clauses provide that:

- The F&A paper must set out, amongst other things, the AER's proposed approach to the application to the distribution network service provider (DNSP) of any CESS<sup>7</sup>
- A regulatory proposal must contain a description, including relevant explanatory material, of how the DNSP proposes any CESS that has been specified in the F&A paper should apply to it<sup>8</sup>
- A building block determination must specify how any applicable CESS is to apply to a DNSP<sup>9</sup>
- The annual revenue requirement must be determined using a building block approach, under which the building blocks include, amongst other things, revenue increments or decrements (if any) arising from the application of any CESS<sup>10</sup>
- The AER must publish capex incentive guidelines that set out, amongst other things, any CESS developed by the AER, and how the AER has taken into account the CESS principles in developing the CESS, and<sup>11</sup>
- In developing a CESS, and in deciding whether to apply a CESS to a DNSP and the nature and details of the CESS that is to apply to the DNSP the AER must:
  - Make a decision in a manner that contributes to the achievement of the capex incentive objective. The capex incentive objective is to ensure that, where the value of a regulatory asset base (RAB) is subject to adjustment in accordance with the NER, then the only capex

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<sup>7</sup> NER, CI 6.8.1(b)(2)(v)

<sup>8</sup> NER, Sch 6.1.3(3A)

<sup>9</sup> NER, CI 6.3.2(a)(3) and NER CI 6.12.1 (9)

<sup>10</sup> NER, CI 6.4.3(a)(5)

<sup>11</sup> NER, CI 6.4A(b)(1)

that is included in an adjustment that increases the value of that RAB is capex that reasonably reflects the capex criteria, and<sup>12</sup>

- Take into account:<sup>13</sup>
  - the CESS principles:
    - DNSPs should be rewarded or penalised for improvements or declines in capex efficiency
    - The rewards and penalties should be commensurate with the efficiencies or inefficiencies in capex, but rewards and penalties need not be symmetric
    - The interaction of the CESS with other incentives that the DNSPs may have in relation to undertaking efficient opex and capex
    - The capex objectives and, if relevant, the opex objectives, and
    - The circumstances of the DNSP.

Schedule 1 of the Reset Regulatory Information Notice (RIN) requires that, where the regulatory proposal varies or departs from the application of any component or parameter of the CESS as set out in the F&A paper, for each variation or departure explain:

- the reasons for the variation or departure, including why it is appropriate
- how the variation or departure aligns with the objectives of the scheme, and
- how the proposed variation or departure will impact the operation of the scheme.<sup>14</sup>

## 2.3 Current application of the CESS

In the current regulatory control period, the CESS, as set out in version 1 of the AER's Capital Expenditure Incentive Guideline applies to us. The CESS, in conjunction with the use of forecast depreciation to roll forward the RAB, works as follows:

- The AER calculates the cumulative underspend or overspend for the current regulatory period in net present value (NPV) terms
- A sharing ratio of 30 per cent is applied to the cumulative underspend or overspend to work out our share of the underspend or overspend
- The AER calculates the CESS payments taking into account the financing benefit or cost to us relating to the overspends or underspends. Also, the AER may make further adjustments to take into account:
  - Deferred capex (where material), and
  - Ex-post exclusions of capex from the RAB due to inefficient overspends, related party margins and changes in capitalisation policies.
- The CESS payments are added or subtracted to our regulated revenue requirements as a separate building block in the 2020-25 regulatory control period, and
- A true-up will be undertaken in the 2025-30 regulatory determination for the difference between actual and forecast underspend or overspend in the final year of the current regulatory period, i.e. 2019-20 .

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<sup>12</sup> NER, Cl. 6.4A(a) and 6.5.8A

<sup>13</sup> NER, Cl 6.5.8A

<sup>14</sup> Reset RIN, Schedule 1, Cl 1.7

The CESS is symmetric. We retain 30 per cent of the benefits or costs of underspending or overspending on capex, while customers retain 70 per cent of the benefits or costs of underspending or overspending on capex.

In the current 2015-20 regulatory control period, we responded to the incentives to reduce capex. We are projecting to underspend the AER's capex allowance. The tables below summarise our capex underspends and the CESS calculations. The detailed calculations are provided in the CESS model provided as Attachment 17.058. As noted earlier, we are currently proposing, subject to the AER's acceptance of our Regulatory Proposal, to forgo the potential revenue adjustment associated with the CESS in this Regulatory Proposal.

**Table 1 Ergon Energy's capex underspend**

\$m Nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Capex allowance	682.54	623.86	584.62	551.56	552.76
Actual capex	628.98	510.78	516.63	563.50	553.22
Underspend	53.56	113.08	67.99	-11.94	-0.45

**Table 2 Ergon Energy's CESS payments**

\$m Nominal	
Total underspend (NPV) adjusted for deferrals	203.88
Relevant sharing ratio	30%
Consumer share	142.72
DNSP share	61.17
Total DNSP financing benefit (NPV)	25.11
NPV of CESS payments (post-adjustment)	36.05

**Table 3 Ergon Energy's CESS payments**

\$m (Real 2019-20)	2020-21	2021-22	2022-23	2023-24	2024-25	Total
CESS payments	7.87	7.87	7.87	7.87	7.87	39.33

### Adjustments to CESS payments for deferred capex

As noted above, the AER may adjust our CESS payments for deferred capex where it is material. Specifically, the Capital Expenditure Incentive Guideline stipulates that the AER will adjust CESS payments when we defer capex and:

- the amount of the deferred capex in the current regulatory control period is material, and
- the amount of the estimated underspend in capex in the current regulatory control period is material, and
- total approved forecast capex in the next regulatory control period is materially higher than it is likely to have been if a material amount of capex was not deferred in the current regulatory control period.

It is not clear to us how the AER will identify the amount of deferred capex and also what constitutes 'material' deferred capex. We expressed this concern in our response to the preliminary F&A paper. For this Regulatory Proposal, we compared the augmentation projects submitted in our 2015-20 and 2020-25 Reset RINs to identify (if any) common projects. We identified five projects and deemed these to be deferred capex. It is not clear whether they are 'material' for the CESS, but we have accounted for the projects as material deferred capex in our CESS calculations summarised above.

The following table sets out the increase in forecast capex we assume is attributable to deferred projects.

**Table 4 Ergon Energy's deferred capex**

\$m (nominal)	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Cannonvale - Switching Station	0.06	0.43	1.67	0.49		2.65
SPD WB AT ISIS T131 OH New to Dallarnil New 37km 132kV SCCP (Energised at 66kV)	10.00	10.60	10.67	10.93		42.21
Broxburn Zone Substation - Rebuild as 110/11kV	5.60					5.60
Gracemere, Modular, 66/11kV, Network, Central	3.51	0.40				3.91
Planella Zone Substation - Convert to 66/11kV	0.24	2.71	5.74			8.69
Total	19.40	14.15	18.08	11.43		63.06

## 2.1 Proposed application of the CESS

We support the AER's intention to continue to apply the CESS in the 2020-25 regulatory control period. We agree with the AER's view that applying the CESS will contribute to the capex incentive objective. We support also the application of the CESS as set out in version 1 of the CESS (and outlined above).

## 3. Efficiency benefit sharing scheme

### 3.2 Overview

The EBSS encourages us to continuously pursue opex efficiency improvements and share these with customers. Under the EBSS, we retain approximately 30 per cent of efficiency gains (or losses) and customers retain 70 per cent.

The EBSS is intrinsically linked to the revealed cost forecasting approach for opex. Under this approach, our forecast opex is based on our actual opex from a recent year – the base year – which is typically the penultimate year of the regulatory period. The EBSS addresses two potential incentive problems arising from this forecasting approach:

- The incentive to increase opex in the base year to increase forecast opex, and
- The incentive to defer efficiency improvements until after the base year.

Using the revealed cost forecasting approach combined with the EBSS results in us earning the same reward and penalty in each year of the regulatory control period.

Given that the EBSS is linked to the revealed cost forecasting approach, the AER's F&A paper indicates that the application of the EBSS is contingent on the AER using the revealed cost forecasting approach, which in turn depends on the efficiency of the base year.

### 3.3 NER and Reset RIN requirements

The EBSS NER requirements are set out in clauses 6.3.2, 6.4.3, 6.5.8, 6.8.1, 6.12.1 and Schedule 6.1.3.

In general, these clauses provide that:

- The F&A paper must set out, amongst other things, the AER's proposed approach to the application to the DNSP of any EBSS<sup>15</sup>
- A regulatory proposal must contain a description, including relevant explanatory material, of how the DNSP proposes any EBSS that has been specified in the F&A paper should apply to it<sup>16</sup>
- A building block determination must specify how any applicable EBSS is to apply to the DNSP
- The annual revenue requirement must be determined using a building block approach, with the building blocks including, amongst other things, revenue increments or decrements (if any) arising from the application of any EBSS<sup>17</sup>
- The AER must develop an EBSS that provides for a fair sharing of efficiency gains and losses in opex between DNSPs and customers. Efficiency gains are derived when actual opex is less than forecast opex, and conversely, efficiency losses are derived when actual opex is greater than forecast opex allowances, and<sup>18</sup>
- In developing and implementing an EBSS, the AER must take into account:<sup>19</sup>
  - The need to ensure that benefits to electricity customers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs
  - The need to provide DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce opex
  - The desirability of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses
  - Any incentives that DNSPs may have to capitalise expenditure, and
  - The possible effects of the scheme on incentives for the implementation of non-network alternatives.

Schedule 1 of the Reset RIN requires that, where the regulatory proposal varies or departs from the application of any component or parameter of the EBSS as set out in the F&A paper, for each variation or departure explain:

- the reasons for the variation or departure, including why it is appropriate
- how the variation or departure aligns with the objectives of the scheme, and
- how the proposed variation or departure will impact the operation of the scheme

### 3.4 Current application of the EBSS

In the current regulatory control period, version 2 of the EBSS currently applies to us.

In summary, the EBSS work as follows:

- The regulatory regime provides for ex-ante opex forecasts. We keep the benefits (or incur the cost) of delivering actual opex at a lower (higher) level than forecast in each year of the regulatory control period
- We retain the incremental efficiency gains and losses for a set period – the carryover period, typically five years – after it makes the efficiency gains or loss

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<sup>15</sup> NER, CI 6.8.1(b)(2)(iv)

<sup>16</sup> NER, Sch 6.1.3(3)

<sup>17</sup> NER, CI 6.4.3(a)(5)

<sup>18</sup> NER, CI 6.5.8 (a)

<sup>19</sup> NER, CI 6.5.8 (c)

- Before the start of the next regulatory control period, the AER calculates carryover amounts for opex efficiency gains or losses made in the regulatory control period
- Carryover amounts are added as an additional building block for next regulatory control period, and
- Actual opex incurred in the base year is used as the starting point for forecasting opex for the next regulatory control period.

Under this approach, we share opex efficiency gains and losses with customers approximately 30:70.

### EBSS carryovers

The tables below summarise our proposed EBSS carryover calculations. The completed EBSS model is provided as Attachment 17.057.

As stipulated in version 2 of the EBSS, we have calculated incremental efficiency gains for the 2015-20 regulatory control period as follows:

- For 2015-16, the first year, as the underspend in the year less the incremental efficiency gain made after the base year in the 2010-15 regulatory control period
- For 2016-17 to 2018-19, the second to penultimate years, as the difference between the underspends in the relevant and previous regulatory years, and
- For 2019-20, the final year, by adjusting for non-current efficiency gains assumed in the base year.

In addition, we excluded the categories of opex in Table 7 from the EBSS. The proposed exclusions are consistent with those specified in the 2010-15 and 2015-20 distribution determinations.

As noted earlier, we are currently proposing, subject to the AER's acceptance of our Regulatory Proposal, to forgo the potential revenue adjustment associated with the CESS in this Regulatory Proposal.

**Table 5 Ergon Energy's EBSS calculation**

\$m (real 2019-20)	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Forecast opex for EBSS	425.5	410.3	363.9	370.1	376.2	384.0	391.3
Adjusted opex for EBSS	386.6	407.6	384.8	415.9	396.2	379.0	361.2
Incremental efficiency gain/(loss)			11.3	-24.8	25.9	25.9	25.1

**Table 6 Ergon Energy's EBSS carryovers**

\$m (real 2019-20)	2020-21	2021-22	2022-23	2023-24	2024-25	Total
EBSS Carryovers	66.3	51.1	75.9	50.1	25.1	268.5

**Table 7 Ergon Energy's EBSS exclusions**

	2010-15 regulatory period	2015-20 regulatory period
Debt raising costs	✓	✓
Self-insurance	✓	✗
Demand management innovation allowance (DMIAM)	✓	✓
Pass through amounts	✓	✓
Defined benefit superannuation	✓	✗
Non-network alternatives	✓	✗
Movements in provisions related to opex	✓	✓
Capitalisation policy changes	✓	✓

### 3.5 Proposed application of the EBSS

The AER's F&A paper indicates that the AER proposes to continue to apply the EBSS in the 2020-25 regulatory control period. However, the AER's decision on the application of the EBSS is conditional on the application of the revealed cost forecasting approach. That is, the AER states that:

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*We will only apply the EBSS in the 2020–25 regulatory control period if we expect we will use a revealed cost forecasting approach to forecast opex for the 2025–30 regulatory control period.<sup>20</sup>*

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We consider that our opex forecasts should be based on our revealed costs. As we outline in our Regulatory Proposal, we have achieved efficiencies over the 2015-20 regulatory control period through the merger savings achieved in Energy Queensland. We project that our opex for the last two years of the current regulatory control period, which includes our nominated base year, will be below the efficient opex forecast determined by the AER for the 2015-20 regulatory control period. That is, our proposed opex is not materially inefficient. Therefore, we support the application of the EBSS in the 2020-25 regulatory control period.

Furthermore, we support the opex adjustments allowed under version 2 of EBSS, namely adjustments for:<sup>21</sup>

- approved pass through amounts or opex for contingent projects
- capitalisation policy changes
- categories of opex not forecast using a single year revealed cost approach for the regulatory control period. In this regard, for the 2020-25 regulatory control period we propose to exclude the following categories:
  - debt raising costs
  - DMIAM, and
- Inflation.

## 4. Service target performance incentive scheme

### 4.1 Overview

The STPIS incentivises us to maintain and improve service performance where customers are willing to pay for the improvements. The scheme is intended to balance the need to achieve efficiency gains by reducing expenditure, as incentivised by the regulatory framework, with the need to maintain and improve service performance.

The AER's STPIS comprises two mechanisms:

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<sup>20</sup> AER, *Final framework and approach for Energex and Ergon Energy for the regulatory control period commencing 1 July 2020*, July 2018, p66

<sup>21</sup> AER, *Efficiency benefit sharing scheme*, November 2013

- a service incentive factor (s-factor) that provides an incentive to maintain average service levels. That is, DNSPs are rewarded and penalised for better or worse performance against set targets via annual adjustments to approved network revenues, and
- a Guaranteed Service Level (GSL) payments scheme that provides payments directly to customers where certain levels of service are not met.

Currently, due to each jurisdiction applying its own GSL payment scheme, only the s-factor component of the STPIS applies to DNSPs.

## 4.2 NER and Reset RIN Requirements

The STPIS NER requirements are set out in Clauses 6.3.2, 6.4.3, 6.6.2, 6.8.1, 6.12.1 and Schedules 6.1.2 and 6.1.3.

In summary, the NER requires that:

- The F&A paper must set out, amongst other things, the AER's proposed approach to the application of any STPIS to a DNSP<sup>22</sup>
- A regulatory proposal must contain:
  - A description, including relevant explanatory material, of how the DNSP proposes any STPIS that has been specified in the F&A paper should apply to it, and<sup>23</sup>
  - the method used for determining the cost associated with planned maintenance programs designed to improve the performance of the relevant distribution system for the purposes of any STPIS that is to apply to the DNSP in respect of the relevant regulatory period.<sup>24</sup>
- A building block determination must specify how any applicable STPIS is to apply to a DNSP<sup>25</sup>
- The annual revenue requirement must be determined using a building block approach, under which the building blocks include, amongst other things, revenue increments or decrements (if any) arising from the application of any STPIS, and<sup>26</sup>
- The AER must develop and publish a STPIS, and in developing and implementing a STPIS, the AER must take into account:<sup>27</sup>
  - consultation with the authorities responsible for the administration of relevant jurisdictional electricity legislation
  - that the service standards and service targets (including GSLs) set by the scheme do not put at risk the DNSP's ability to comply with relevant service standards and service targets (including guaranteed service levels) as specified in jurisdictional electricity legislation
  - the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty
  - any regulatory obligation or requirement to which the DNSP is subject
  - the past performance of the distribution network
  - any other incentives available to the DNSP under the NER or a relevant distribution determination

<sup>22</sup> NER, CI 6.8.1(b)(2)(iii)

<sup>23</sup> NER, Sch 6.1.3(4)

<sup>24</sup> NER, S6.1.2(4)

<sup>25</sup> NER, CI 6.3.2(a)(3) and NER CI 6.12.1 (9)

<sup>26</sup> NER, CI 6.4.3(a)(5)

<sup>27</sup> NER, CI 6.6.2

- the need to ensure that the incentives are sufficient to offset any financial incentives the DNSP may have to reduce costs at the expense of service levels
- the willingness of the customer or end user to pay for improved performance in the delivery of services
- the possible effects of the scheme on incentives for the implementation of non-network options, and
- the Distribution Reliability Measures Guidelines

Schedule 1 of the Reset RIN requires that:

- Where the regulatory proposal varies or departs from the application of any component or STPIS as set out in the F&A paper, for each variation or departure explain:<sup>28</sup>
  - the reasons for the variation or departure, including why it is appropriate
  - how the variation or departure aligns with the objectives of the relevant scheme, and
  - how the proposed variation or departure will impact the operation of the relevant scheme.
- Provide Ergon Energy's detailed methodology for calculating the following parameters used in the STPIS<sup>29</sup>
  - the SAIDI and SAIFI targets for each supply reliability area
  - the customer service parameters and targets
  - daily SAIDI and SAIFI and customer service performance derived from the individual interruption data under paragraph
  - the major event day (MED) threshold derived from the daily SAIDI data, and
  - the incentive rates to apply to each supply reliability area.

Note: All calculations must be made in accordance with the STPIS and using data which complies with the STPIS definitions. Ergon Energy must provide their SAIDI and SAIFI targets for each supply reliability area and not its forecasted SAIDI and SAIFI for each supply reliability area
- If Ergon Energy proposes adjustments to the STPIS targets away from those based upon raw historical data Ergon Energy must provide, in respect of each adjustment:<sup>30</sup>
  - the reasons for the adjustment
  - the quantum of the adjustment, and the effect of the adjustment on the targets for each of the supply reliability areas, and
  - the method, basis and empirical data used as justification for the adjustment, and
- Provide the data required in Workbook 1 – Regulatory determination, regulatory templates 6.1 and 6.2.<sup>31</sup>

### 4.3 Current application of the STPIS

The AER's STPIS published in November 2008 applies to us in the current regulatory control period.

**The AER's STPIS outlines how the STPIS works.**

Table 8 sets out the specific aspects of the STPIS that apply to us.

<sup>28</sup> Reset RIN, CI 1.7

<sup>29</sup> Reset RIN, CI 19

<sup>30</sup> Reset RIN, CI 19

<sup>31</sup> Reset RIN, CI 19

**Table 8 Current application of the STPIS**

Issue	2015-20 AER Determination
Revenue at risk	±2 per cent
Segmenting of network	Central Business District (CBD), urban, short rural and long rural
Applicable parameters for the s-factor	Reliability of supply: SAIDI and SAIFI Customer service: telephone answering
Performance targets	Based on the average performance over the past five regulatory years.
Criteria for excluding certain events from s-factor calculations	Applied the methodology indicated in the national STPIS – the 2.5 beta method for calculating MED
Incentive rates	Applied the methodology indicated in the national STPIS and the value of customer reliability (VCR) for Queensland from the Australian Energy Market Operator's (AEMO) 2014 study.
GSL component	Not applied

## 4.4 Proposed application of the STPIS

We support the AER's decision in its F&A paper to continue to apply the STPIS in the 2020-25 regulatory control period. In addition, we broadly support the application of the revised STPIS (version 2) published on 14 November 2018. We note that, in the F&A paper, the AER indicated that the revised STPIS would apply to us if the review was completed in time. Key changes in the revised STPIS include:

- the change of momentary interruption threshold from 1 minute or less to 3 minutes or less, and
- adjusting the incentive rate weighting between SAIDI and SAIFI from the current approximately 50:50 ratio to 60:40 ratio.

### 4.4.1 Proposed revenue at risk

We support the AER's decision in its F&A paper to continue to set the revenue at risk at ±2 per cent. In light of our strong historical reliability and customer service performance, we consider a lower powered scheme remains appropriate in Queensland.

We also propose a cap of ±0.2 per cent for the customer service parameter.

### 4.4.2 Proposed segmentation of the network

We accept the AER's decision in its F&A paper in relation to the segmentation of the network. That is, we will segment our network using the following feeder categories as they are defined in the STPIS:

- CBD
- Urban
- Short rural, and
- Long rural

However, we note that the CBD feeder category does not currently apply in Ergon Energy's distribution area.

#### 4.4.3 Applicable parameters for the s-factor

We support the AER's decision in its F&A paper to continue to apply the unplanned SAIDI and SAIFI as the reliability of supply parameters, and telephone answering as the customer service parameter.

#### 4.4.4 Proposed exclusions

We support the AER's decision in its F&A paper to apply the method outlined in the STPIS for excluding specific events from the calculation of annual performance and performance targets. Clause 3.3 of the STPIS sets out the exclusions allowed when calculating the reliability of supply performance and targets. Furthermore, clause 5.4 of version of the STPIS stipulates that the exclusions in Clause 3.3, used to calculate reliability of supply performance and targets, can also be used to calculate the 'telephone answering' customer service parameter.

We also support the methodology for determining the MED threshold in appendix D of the STPIS. The methodology is based on the Institute for Electrical and Electronic Engineers Standards 1366, called the 2.5 beta method.

#### 4.4.5 Reliability of supply performance targets

The table below sets out our proposed targets for the 2020-25 regulatory control period. The STPIS model provided as Attachment 11.008 outlines the detailed calculations. We summarise how we have developed our targets below.

**Table 9 Ergon Energy proposed targets**

Proposed targets	
<b>Unplanned SAIDI</b>	
CBD	N/A
Urban	105.91
Short rural	276.72
Long rural	758.23
<b>Unplanned SAIFI</b>	
CBD	N/A
Urban	1.250
Short rural	2.642
Long rural	5.303

In developing our proposed targets we adopted the approach proposed in the F&A paper decision and the STPIS. That is, our performance targets for the forthcoming regulatory control period are based on our average performance over the past five regulatory years. For purposes of this Regulatory Proposal we have used the five years from 2013-14 to 2017-18. We will update the five year historical period to 2014-15 to 2018-19 in our Revised Regulatory Proposal. Also, consistent with the STPIS, we propose to modify our average performance over the past five years as outlined below.

#### Back-casting our reliability performance

As noted above, the AER's revised STPIS amends, amongst other things, the thresholds of momentary interruption from 1 minute or less to 3 minutes or less and the exclusions under clause 3.3 of the national STPIS removed from annual performance. As a result of these amendments, if the systems are able we have back-casted our reliability of supply performance over the past five years to ensure that our future targets are consistent with how the annual performance will be measured in the 2020-25 regulatory control period.

In calculating our reliability of supply performance we use the following process (and assumptions) which primarily relies on the network and customer interruption information from our Outage Management Systems.

Targets are calculated utilising normalised reliability performance data. To "normalise" the reliability of supply data the following is applied:

- a. an interruption defined as more than 0.5 seconds
- b. sustained Interruptions (note: Momentary Interruptions (three minutes or less) are excluded)
- c. all active customers with active National Metering Identifiers are considered and all inactive customers excluded (as per the annual performance definitions)
- d. unplanned interruptions (note: Planned Interruption Events are excluded)
- e. exclusions outlined in clause 3.3 of the national STPIS (Nov 2018) including MED exclusion have been excluded. (Back-casted if systems are able)  
(MED utilises the daily SAIDI which is calculated for the purpose of identifying whether a day exceeds the threshold to be excluded, but the same is not required for SAIFI.)
- f. customers connected to the distribution feeders of the regulated network with a feeder classification of CBD / Urban / Short Rural or Long Rural. (i.e. customers that are connected to the transmission / su-transmission network or unregulated networks are excluded.)
- g. The feeder classifications are determined under the national STPIS (Nov 2018) Appendix A
  - CBD feeder means a feeder in the CBD area of a State or Territory capital; and other equivalent areas that are applicable in the relevant participating jurisdiction as supplying predominantly commercial, high-rise buildings, supplied by a predominantly underground distribution network containing significant interconnection and redundancy when compared to urban areas
  - urban feeder means a feeder, which is not a CBD feeder, has a 3-year average maximum demand over the 3-year average feeder route length greater than 0.3 MVA/km
  - short rural feeder means a feeder which is not a CBD or urban feeder with a total feeder route length less than 200 km, and
  - long rural feeder a feeder which is not a CBD or urban feeder.

NOTE: The distribution network sections that are part of Ergon Energy's unregulated assets are not included in the STPIS. For clarification, the Mount Isa – Cloncurry supply network is considered regulated. All other isolated networks are considered unregulated.

- h. The customer minutes and customers interrupted are aggregated by network type for the reporting period (regulatory year)
- i. the contribution of each event to the performance under the reliability of supply parameters of the STPIS is calculated as a ratio of the event interrupted customers or interrupted customer minutes to the network type average distribution customer count derived at the end of the regulatory year
- j. The average distribution customer count associated with the particular network type over the regulatory year is the average between the customer count taken at start (1 July) and end (30 June) of the regulatory year, and
- k. the outcome is the network type SAIDI and SAIFI for the reporting period.

### **Revenue at risk adjustments**

Under the STPIS, we can adjust our performance targets where our past performance exceeded the revenue at risk thresholds. We note that the revised STPIS provides a formula for making these adjustments. However, we have been unable to apply the formula in developing our targets as the formula is unclear. Therefore, we propose to depart from the STPIS formula and apply the approach used in the 2015-20 distribution determination.

Our proposed methodology is to reduce the s-factor for each reliability parameter in proportion to its contribution, such that their sum equals the revenue cap applicable to the reliability parameters (1.8%) in each year. The reduced s-factor for each reliability parameter is then used to calculate the adjusted performance for that year. It works as follows:

1. Determine the “raw” s-factor for each reliability parameter in the year that the revenue cap was exceeded. This is done by taking the actual SAIDI or SAIFI performance achieved in the year, subtracting it from its respective target, and then multiplying by the incentive rate for that parameter
2. Summate the individual raw s-factors for each parameter to calculate an overall raw s-factor
3. Determine the ratio between the overall raw s-factor and the capped s-factor (1.8%)
4. Pro rate the s-factor for each parameter by the ratio calculated in (3). These adjusted s-factors should now summate to equal the reliability revenue at risk cap (1.8%), and
5. Convert the adjusted s-factor for each parameter back to a SAIDI or SAIFI value by multiplying it by its incentive rate and then adding it to its respective SAIDI or SAIFI target.

These adjusted SAIDI and SAIFI values then replace the actual values achieved in that year when calculating the five year average. Our full calculations are provided in the attached STPIS model.

### **Funded reliability improvements**

Ergon Energy’s strategy for reliability of supply improvement over the next regulatory control period is focused on Worst Performing Feeder improvement as detailed in Ergon Energy’s Distribution Authority. The feeders considered for investment under this strategy generally supply a very low customer base and as such any marginal improvement achieved at the feeder level will not result in a material improvement to supply reliability at the network type average level. Therefore the average

performance over the past five years has not been modified when determining the proposed reliability performance targets for the next regulatory control period.

#### 4.4.6 Customer service performance targets

The table below sets out our proposed target for the telephone answering. The detailed calculations are set provided in the attached STPIS model.

**Table 10 Ergon Energy's proposed telephone answering target**

	2020-21	2021-22	2022-23	2023-24	2024-25
Telephone answering	80.24	80.24	80.24	80.24	80.24

Consistent with the F&A paper decision and the STPIS, we have calculated our proposed targets based on our actual performance over the past five years. In addition, in accordance with Clause 5.3.1(b) of the STPIS, we have modified our five year average performance for years when our performance exceeded the customer service revenue at risk cap of  $\pm 0.2$  per cent. Our proposed approach to making this adjustment is to substitute our actual (raw) performance with the implied performance that meets the revenue at risk cap in the years where actual performance exceeded the cap.

#### 4.4.7 Proposed incentive rates

##### Reliability of supply

The table below sets out our proposed incentive rates for the 2020-25 regulatory control period. The attached STPIS model provides our detailed calculations of the incentive rates.

**Table 11 Ergon Energy's proposed incentive rates**

Incentive rates	
<b>Unplanned SAIDI</b>	
CBD	N/A
Urban	0.0162
Short rural	0.0193
Long rural	0.0042
<b>Unplanned SAIFI</b>	
CBD	N/A
Urban	0.9161
Short rural	1.3465
Long rural	0.3973

In summary, we calculated our proposed incentive rates in accordance with the Clause 3.2.2 and the formulae in Appendix B of the STPIS. Our key assumptions include:

- **Value of Customer Reliability.** Consistent with the F&A paper, we propose the VCR estimates from AEMO 2014 Value of Customer Reliability Review final report. For our urban and rural feeders we propose the Queensland state level VCR in table 25 of AEMO's report (i.e. \$39,710 MWh). We have adjusted AEMO's VCR estimates for the Consumer Price Index (CPI)
- **Weighting for unplanned SAIDI and unplanned SAIFI.** We have adopted the weightings set out in the revised STPIS of approximately to 60:40

- **Expected average annual energy consumption by network type for the 2020-25 regulatory control period.** We currently do not develop energy consumption forecasts by network type. Therefore, we have applied the average consumption ratios from our past five years to our overall forecast energy consumption data, and
- **Average smoothed annual revenue requirement.** We have used the value provided in our proposed post-tax revenue model (PTRM) provided as Attachment 8.004.

### Customer service - telephone answering

We propose the incentive rate of -0.040 per cent per unit of the customer service telephone answering parameter as set out in the STPIS clause 5.3.2(a).

## 5. Demand management incentive scheme and demand management innovation allowance mechanism

### 5.1 Overview

The NER provides for a demand management incentive framework to encourage us to pursue efficient demand management projects when these are at least as efficient as network capital investment. In accordance with the NER, in December 2017, the AER published:

- the new DMIS, which provides DNSPs with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management, and
- The revised DMIAM, which provide DNSPs with funding for research and development (R&D) in demand management projects that have the potential to reduce long term network costs. The revised DMIAM is similar in design to the AER's current Demand Management Innovation Allowance (DMIA). It provides an ex-ante R&D allowance and any underspend of the allowance is returned to customers in the following regulatory control period.

In the F&A paper, the AER proposed to apply the recently developed DMIS and revised DMIAM in the 2020-25 regulatory control period. We support the application of both.

### 5.2 NER and Reset RIN Requirements

The DMIS and DMIAM requirements are set out in Clauses 6.3.2, 6.4.3, 6.6.3, 6.8.1, 6.12.1 and Schedules 6.1.2 and 6.1.3.

In summary, the NER requires that:

- The F&A paper must set out, amongst other things, the AER's proposed approach to the application of any DMIS or DMIAM to a DNSP<sup>32</sup>
- A regulatory proposal must contain A description, including relevant explanatory material, of how the DNSP proposes any DMIS or DMIAM that has been specified in the F&A paper should apply to it<sup>33</sup>
- A building block determination must specify how any applicable DMIS or DMIAM is to apply to a DNSP<sup>34</sup>

<sup>32</sup> NER, CI 6.8.1(b)(2)(iv)

<sup>33</sup> NER, Sch 6.1.3(5)

<sup>34</sup> NER, CI 6.3.2(a)(3) and NER CI 6.12.1 (9)

- The annual revenue requirement must be determined using a building block approach, under which the building blocks include, amongst other things, revenue increments or decrements (if any) arising from the application of any DMIS or DMIAM<sup>35</sup>
- The AER must develop and publish a DMIS, and in developing and applying a DMIS, the AER must take into account:<sup>36</sup>
  - the DMIS should be applied in a manner that contributes to the achievement of the DMIS objective: to provide DNSPs with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management
  - the DMIS should reward DNSPs for implementing relevant non-network options that deliver net cost savings to retail customers
  - the DMIS should balance the incentives between expenditure on network options and non-network options relating to demand management
  - the net economic benefits delivered to all those who produce, consume and transport electricity in the market associated with implementing relevant non-network options
  - the level of the incentive:
    - should be reasonable, considering the long term benefit to retail customers
    - should not include costs that are otherwise recoverable from any another source, including under a relevant distribution determination, and
    - may vary by DNSP and over time.
  - penalties should not be imposed on DNSP under any DMIS
  - the incentives should not be limited by the length of a regulatory control period, if such limitations would not contribute to the achievement of the DMIS objective, and
  - the possible interaction between the DMIS and:
    - any other incentives available to the DNSP in relation to undertaking efficient expenditure on, or implementation of, relevant non-network options
    - particular control mechanisms and their effect on a DNSP's available incentives, and
    - meeting any regulatory obligation or requirement.
- The AER must develop and publish a DMIAM, and in developing and applying a DMIAM, the AER must take into account:<sup>37</sup>
  - the DMIAM should be applied in a manner that contributes to the achievement of the DMIAM mechanism objective: to provide DNSPs with funding for research and development in demand management projects that have the potential to reduce long term network costs
  - demand management projects, to which the DMIAM applies, should have the potential to deliver ongoing reductions in demand or peak demand, and be innovative and not be otherwise efficient and prudent non-network options that a DNSPs should have provided for in its regulatory proposal, and
  - the level of the allowance, under the DMIAM:
    - should be reasonable, considering the long term benefit to retail customers

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<sup>35</sup> NER, CI 6.4.3(a)(5)

<sup>36</sup> NER, CI 6.6.3A

<sup>37</sup> NER, CI 6.6.3A

- should only provide funding that is not available from any another source, including under a relevant distribution determination, and
- may vary by DNSP and over time.

Schedule 1 of the Reset RIN requires that, where the regulatory proposal varies or departs from the application of any component or parameter of the DMIS or DMIAM as set out in the F&A paper, for each variation or departure explain:<sup>38</sup>

- the reasons for the variation or departure, including why it is appropriate
- how the variation or departure aligns with the objectives of the scheme, and
- how the proposed variation or departure will impact the operation of the scheme

### 5.3 Current application of the DMIA

In the 2015-20 distribution determination, the AER applied Part A of its current DMIS – the DMIA – which is a capped allowance for DNSPs to investigate innovative demand management projects. The AER incorporated a \$1 million (\$2014-15) innovation allowance into our annual revenues for the 2015-20 regulatory period (or \$5 million over the regulatory period). We are required to prepare annual reports on our expenditure under the DMIA which the AER assesses against specific criteria. Any underspend against the innovation allowance will be returned to customers in the 2020-25 regulatory period.

The table below sets out our current expenditure under the current DMIA.

**Table 12 Ergon Energy 2015-20 DMIA expenditure**

\$m nominal	2015-16	2016-17	2017-18
DMIA	0.33	0.79	0.26

The key projects comprising this expenditure include:

- After Diversity Maximum Demand calculator developer pilot
- Feeder of the future – home energy management
- Feeder of the future – meter probe reads
- Feeder of the future – smart meter installation
- Low Power Wide Area Network (LPWAN) load control
- Grid advocacy
- Centralised Energy Storage Systems stage 2
- Proprietary Home Energy Management System (HEMS) end-to end bench testing
- Internet Protocol Demand Response Enabling Device (IPDRED) development
- Lakeland Solar & Storage, and
- Solar analytics – customer devices enabling renewables

### 5.4 Proposed application of the DMIS and DMIAM

As noted above, in the F&A paper, the AER proposes to apply its new DMIS and revised DMIAM, published in December 2017, in the 2020-25 regulatory control period. We support the application of the new DMIS and revised DMIAM as summarised below.

<sup>38</sup> Reset RIN, CI 1.7

#### 5.4.8 The DMIS

The AER's new DMIS incentivises us to pursue efficient demand management projects by providing a return or uplift on the expected costs of efficient demand management projects. The AER proposes to apply an uplift of 50%. However, the incentive is subject to two caps:

- The project cap - this stipulates that the total incentive payable cannot exceed the expected net benefits of the project. This cap aims to have every project that receives the incentive deliver either a positive or a neutral benefit to retail electricity customers ex-ante, and
- The overall cap - this cap prevents a distributor's total incentive for a regulatory year from exceeding 1.0 per cent of maximum allowable revenue for that year.

Broadly speaking, the new DMIS will apply as follows:

- Identifying and committing eligible projects – The DNSP must first identify via Regulatory Investment Test – Distribution (RIT-D) or minimum project evaluation requirements any preferred non-network options relating to demand management. The DNSP must commit to deliverables under each project
- Determining the incentive for eligible projects – The DNSP then determines the project incentive for an eligible project that delivers a net benefit to retail customers
- Compliance reporting – The DNSP reports data on the past regulatory year, including the financial incentive it accrued, how it identified eligible projects and the costs, benefits and outputs of eligible projects
- AER determines the financial incentive – AER reviews the total financial incentive a distributor accrued and publishes a performance report on how DNSPs used the scheme, and
- Application of incentive payment – The total financial incentive a DNSP accrued in regulatory year  $t-2$  is included in the DNSP's annual revenue requirement for regulatory year  $t$ .

#### Proposed DMIS projects

In the 2020-25 regulatory control period, we expect to seek DMIS incentive payments related to:

- Our Target Area Incentives Programs. These programs offer incentive payments to customers in target areas where demand reductions are required address future network constraints or risks, and
- New non-network alternative generation contracts.

#### 5.4.9 The DMIAM

The revised DMIAM is similar in design to the current DMIA; it will provide an ex-ante allowance to DNSPs to undertake innovative projects related to demand management. Any amount of the allowance that is underspend is returned to customers in a subsequent regulatory control period.

Broadly speaking, the DMIAM will work as follows:

- The AER will determine, in a distribution determination, the maximum amount of the allowance for the regulatory period as the sum of:
  - \$200,000 (in 2017 dollars, where the AER accounts for inflation using CPI) for each year of the regulatory period, and

- 0.075% of the DNSP's maximum allowable revenue (MAR) as determined in that distribution determination at the time the distribution determination is first made.
- The DNSP identifies eligible projects against the AER's project criteria, and must implement the projects
- The DNSP submits annual compliance reports, and the AER uses the compliance reports to approve expenditure and publish a performance report on how DNSPs used the DMIAM, and
- In the second year of the subsequent regulatory control period, the AER determines and applies any carryover amount from underspending the allowance as a deduction from the DNSP's MAR.

The following table summarises our forecast DMIAM allowances determined using the approach outlined above. The detailed calculations are included in the PTRM provided as Attachment 8.004.

**Table 13 Ergon Energy DMIAM allowance**

\$m 2019-20	2020-21	2021-22	2022-23	2023-24	2024-25
DMIAM	1.10	1.11	1.11	1.12	1.13

### Proposed DMIAM projects

Over the next regulatory control period and ultimately over the next two decades, we anticipate that electricity network business will significantly evolve as we face the challenges of increasing:

- levels of intermittent and controllable distributed energy resources
- active energy service providers
- emphasis on the role of distribution networks on the overall system and market operation.
- peakiness in network demand, and
- opportunities to use non-traditional technologies to resolve network issues such as constraints.

As a result, we are proposing to use our DMIAM allowances undertaking projects related to:

- **Managing two way energy flows.** Reverse energy flows from widespread installation of distributed solar PV have resulted in emerging network impacts that must be managed. Improved monitoring and visibility, and extended control across the low voltage network is essential
- **Efficient investment decision-making.** As the electricity network continues to evolve and become more complex, more sophisticated network planning tools will be required to ensure the network remains fit for purpose
- **Incentivising customer efficiency and innovation.** To promote long term efficient network utilisation, more cost reflective financial signals will be increasingly implemented and refined
- **Active customer response enablers.** In Queensland, customer demand response has been enabled by Audio Frequency Load Control (AFLC) since the 1950s. However, new options are emerging that will lead to the replacement of AFLC, and
- **Transforming supply in remote areas.** Remote areas of Queensland are primarily supplied by Single Wire Earth Return (SWER) and diesel fuelled isolated networks. Investigating conversion of SWER networks to microgrids or standalone power systems will become more viable as energy storage costs decrease.

## 6. Definitions, acronyms, and abbreviations

This section contains definitions for all acronyms, technical terms, and abbreviations used in the document.

Acronym	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ALFC	Audio Frequency Load Control
Capex	Capital expenditure
CBD	Central Business District
CESS	Capital Expenditure Sharing Scheme
CPI	Consumer Price Index
DMIA	Demand Management Innovation Allowance
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
EBSS	Efficiency Benefit Sharing Scheme
Energex	Energex Limited
Ergon Energy	Ergon Energy Corporation Limited
F&A	Framework and Approach
GSL	Guaranteed Service Level
MAR	Maximum Allowable Revenue
MED	Major Event Day
NER	National Electricity Rules
Opex	Operating expenditure
PTRM	Post Tax Revenue Model
RAB	Regulatory Asset Base
RIN	Regulatory Information Notice
R&D	Research and Development
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SSIS	Small-Scale Incentive Scheme
STPIS	Service Target Performance Incentive Scheme
VCR	Value of Customer Reliability