Service Target Performance Incentive Scheme

Submission

to

AER Preliminary Positions

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CONTACT

This document is the responsibility of the Commercial Management Group within the Network Division of Aurora Energy Pty Ltd (ABN 85 082 464 622). Please contact the indicated owner of the document with any queries or suggestions.

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AURORA ENERGY PTY LTD

Submission to AER Service Target Performance Incentive Scheme

Version History

Version No	Date of Revision	Authorised By	Details of Amendment
1.0	September 2010	Network Regulatory Analyst	Initial Version
1.1	September 2010	Group Manager – Commercial Management	Final Version
2.0	October 2010	Commenrcial Manager - Network	Approved for submission

Amendments to each version of this document will be tracked through Aurora's document management system.

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1. Introduction

1.1. Background

Aurora Energy Pty Ltd (Aurora) is a Tasmanian Government owned electricity distribution, generation and energy retail company. It was formed in July 1998 pursuant to the Electricity Companies Act 1997 and incorporated under the Corporations Law. It has two shareholders, the Minister for Energy and the Treasurer.

As the monopoly provider of distribution services within the Tasmanian jurisdiction, Aurora is required to hold a distribution licence in accordance with the Electricity Supply Industry Act 1995 (ESI Act). This licence was issued in December 1998 and authorises Aurora to distribute electricity on mainland Tasmania subject to certain conditions and regulatory controls.

In this document, reference to Aurora should be taken as reference to Aurora in its capacity as a regulated provider of distribution network services on mainland Tasmania.

Since its creation in 1998, the economic regulation of Aurora has been jurisdictionally based. In line with the Australian Energy Market Agreement (AEMA) the responsibility for the economic regulation of Aurora is to be transferred to the Australian Energy Regulator no later than 1 July 2012, which is also the proposed commencement date of the next regulatory control period.

As a result of this future transition of powers, the AER has commenced the process leading to economic regulation of Aurora for the regulatory control period due to start on 1 July 2012 with the issue for consultation of the *Preliminary Positions, Framework and Approach Paper, Aurora Energy Pty Ltd, Regulatory Control Period Commencing 1 July 2012* in June 2010 (the Preliminary Position Paper). A Service Target Performance Incentive Scheme (STPIS) is a component of the regulation that must be applied by the AER, and the Preliminary Positions Paper contains the AER's first thoughts on the application of a STPIS to Aurora.

Aurora responded to the Preliminary Positions Paper in August 2010.

This paper further addresses the application of the STPIS to Aurora for the regulatory control period commencing 1 July 2012.

1.2. Terms Used

2003 Determination	*Investigation into Electricity Supply Industry Pricing Policies Declared Electrical Services Pricing Determination*, issued by the Regulator on 27 November 2003
2003 Final Report	*Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania Final Report and Proposed Maximum Prices*, published by the Regulator in September 2003
2007 Determination	*Investigation into Electricity Supply Industry Pricing Policies Declared Electrical Services Pricing*

	Determination, issued by the Regulator on 31 November 2007
2007 Draft Report	*Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania Draft Report and Proposed Maximum Prices*, published by the Regulator in July 2007
2007 Final Report	*Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania Final Report and Proposed Maximum Prices*, published by the Regulator in September 2007
AARR	Aggregate Annual Revenue Requirement
AEMA	Australian Energy Markets Agreement
AER	Australian Energy Regulator
Aurora	Aurora Energy Pty Ltd ABN 85 082 464 622
CAIDI	Customer Average Interruption Duration Index
CBD	Central Business District
CPI	Consumer Price Index
DNSP	Distribution Network Service Provider
Draft SIS Position Paper	*Draft Position Paper Service Incentive Scheme* issued by the Regulator in May 2007
ESI Act	Electricity Supply Industry Act 1995
GSL	Guaranteed Service Level
GSL Guideline	*Guaranteed Service Level (GSL) Scheme* Version 2, a Guideline issued by the Regulator in December 2007
GSL Scheme	Guaranteed Service Level Scheme
kVA	kiloVolt Amps
MAIFI	Momentary Average Interruption Frequency Index
MWh	MegaWatt hour
NEL	National Electricity Law
NER	National Electricity Rules
OTTER	Office of the Tasmanian Energy Regulator / Office of the Tasmanian Economic Regulator
Performance Reporting Guideline	*Electricity Supply Industry Performance and Information Reporting Guideline*, version 1.1 issued by the Regulator in May 2009
Preliminary Positions Paper	*Preliminary Positions, Framework and Approach Paper, Aurora Energy Pty Ltd, Regulatory Control Period Commencing 1 July 2012* in June 2010
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
STPIS	Service Target Performance Incentive Scheme
STPIS Guideline	Guideline "*Electricity distribution network service*

	providers Service target performance incentive scheme" issued by the AER in November 2009
TEC	Tasmanian Electricity Code
VCR	Value of Customer Reliability

2. Tasmanian Regulatory Arrangements

2.1. Introduction

As a result of the AEMA, the Tasmanian jurisdiction is currently in transition between economic regulators: the Tasmanian Regulator (Regulator) has been responsible for the economic regulation of Aurora since 1998, with the AER assuming responsibility for the economic regulation of Aurora's distribution activities on 1 July 2012. This section provides a background to the Tasmanian Regulatory arrangements currently in place, and those expected to be in place under the new regime.

2.2. Before 1 July 2012

The operation of the electricity industry in Tasmania is primarily under the auspices of the ESI Act. The ESI Act creates the position of the Regulator with powers to oversee the operation of the energy sector, which includes the creation and administration of the Tasmanian Electricity Code (TEC).

Aurora is licensed by the Regulator as a distributor under the ESI Act, with the initial license granted on 21 December 1998 and renewed on 21 December 2008. As a licensed entity, the economic regulation of Aurora is administered by the Regulator under the ESI Act, Electricity Supply Industry (Price Control) Regulations, and chapter 6 of the TEC.

The Regulator has conducted 3 pricing investigations under the ESI Act, covering the periods:

- 1 January 2000 to 31 December 2002, extended to 31 December 2003
- 1 January 2004 to 31 December 2007; and
- 1 January 2008 to 30 June 2012.

2.3. After 30 June 2012

As a result of the AEMA, the responsibility for economic regulation of Aurora will transfer to the AER no later than 1 July 2012. The AER will regulate Aurora under the NEL and NER. Nonetheless, the Regulator has indicated that Aurora will remain licensed under the ESI Act. In consequence, Aurora must still comply with the ESI Act, TEC and Regulator's guidelines.

3. Service Incentive Scheme 2004 -2007

3.1. Introduction

The Regulator implemented a range of performance monitoring mechanisms, summarised in Table 4.2 of the Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania Final Report and Proposed Maximum Prices issued in September 2003 (the 2003 Final Report):

- a Service Incentive Scheme based on monetary penalties associated with state-wide SAIDI and SAIFI targets;
- a GSL scheme;
- reporting of feeder performance and feeder category averages to provide incentive for SAIDI and SAIFI improvements in all areas of the state;
- reporting of MAIFI; and
- Customer Charter Guarantees – no financial penalty but reporting

3.2. Service Incentive Scheme

Standards for the Service Incentive Scheme were developed by the Regulator based upon historical performance data provided by Aurora and reflecting the performance gains expected through the capital expenditure program[1] for the regulatory control period (see Table 1).

Table 1 Annual Performance Targets 2003 - 2007

Year Ended 30 June	2003	2004	2005	2006	2007
SAIDI	185.0	181.0	165.5	154.0	144.4
SAIFI	2.153	2.123	2.015	1.910	1.817

Annual state-wide performance targets developed by the Regulator for use in the Service Incentive Scheme. Reference: tables 4 & 5 of Schedule 1 of the 2003 Determination

The Regulator provided that days classified as “Major Event Days” could be removed from the state-wide SAIDI and SAIFI calculations. The Major Event Day threshold of 6.06 minutes for a day’s SAIDI was calculated by the Regulator based on historical data and applied for the duration of the regulatory period[2]. Any day that was classified as a Major Event Day was excluded from the state-wide data-set, and the average daily SAIDI and SAIFI substituted.

Outages caused by the following were also excluded from state-wide SAIDI and SAIFI calculations:

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[1] 2003 Final Report, section 4.3.1.

[2] 2003 Final Report, p118

- transmission outages;
- third party outages (car hit pole, etc); and
- customer installation faults.

The scheme itself is described in section 4.3.1.2 of the 2003 Final Report. In brief, the financial incentives were capped at ±$1.6 million of AARR (that is, about 1.25% of AARR), split evenly between SAIDI & SAIFI. This translated to approximately ±$26,000 for every 1 minute away from the SAIDI target and for every 0.01 interruptions away from the SAIFI targets, with the values in $2002 (see Table 1 for targets). The amounts were indexed by CPI and calculated at the end of each regulatory year and applied to the following year's revenue. Aurora's performance against the targets, and the associated penalties, are given in Table 2.

Table 2 Aurora's Performance Against Service Incentive Scheme Targets 2004-2007

Year Ended 30 June	2004	2005	2006	2007
SAIDI Target	181.0	165.5	154.0	144.4
SAIDI Performance	216.0	170.0	182.0	188.0
SAIDI Penalty	$ 800,000 [Note 1]	$ 117,000	$ 728,000	$800,000 [Note 3]
SAIFI Target	2.123	2.015	1.910	1.817
SAIFI Performance	2.45	2.09	1.96	1.90
SAIFI Penalty	$ 800,000 [Note 2]	$ 195,000	$ 130,000	$ 215 800
Total Penalty	$ 1,600,000	$ 312,000	$ 858,000	$1,015,800

Aurora's performance against its Service Incentive Scheme targets and associated penalties. Reference: table 4.1 of the Preliminary Positions Paper.

Note 1: without cap would have been $910,000. Note 2: without cap would have been $850,200. Note 3: without cap would have been $1,133,600.

A Note on Calculation of SAIDI and SAIFI

Strictly, SAIDI and SAIFI are calculated according to customer numbers

SAIDI = (Customer Outage Duration)/(Total Customers)

SAIFI = (Customers Affected) / (Total Customers)

As Aurora did not have viable customer connectivity data available, connected kVA (the kVA of the transformers serving the customers) was used as a proxy for customer numbers. That is,

SAIDI = (kVA Outage Duration)/(Total Connected kVA)

SAIFI = (kVA Outage)/(Total Connected kVA)

This approach was used for both the targets and reporting against these targets.

3.3. Guaranteed Service Level Scheme

The GSL scheme for this regulatory control period was not developed in time for inclusion in the final determination. Nonetheless, Aurora agreed with the Regulator to include the finalised GSL scheme in its customer charter, provision of which was a requirement under section 8.3.1 of the TEC.

The basis of the agreed scheme was the *Guaranteed Service Levels Principles*, with version 1.0 being issued by the Regulator in October 2003. The main points are:

- customers who experienced an outage of duration longer than 12 hours qualified for an $80 GSL payment;
- customers living in the urban areas of Hobart, Launceston, Devonport or Burnie who experienced 10 outages in a 12-month period qualified for an $80 GSL payment;
- customers living elsewhere who experienced 16 outages in a 12 month period qualified for an $80 GSL payment;
- some outages were excluded from consideration – customer agreement to the outage, outage to an unmetered supply, service fuse failure, disconnection for certain conditions;
- Aurora was able to apply for an exemption if the outage was "widespread" and "…of such a scale that in the opinion of the Regulator, the Distributor is not reasonably able to mitigate against";
- payment was on a 12-month rolling basis – if an excessive count payment was triggered the count went back to 0;
- payment was automatic – there was no need for customers to apply; and
- payment was theoretically to the customer, but actually to an installation.

Funding was provided in the AARR to cover the expected GSL liability at the historical performance level and the additional costs of infrastructure and administration[3].

Aurora's performance under the GSL scheme is given in Table 3.

[3] 2003 Final Report, page 80.

Table 3 GSL Payment Numbers and Values - 2004 to 2007

Year ended 30 June	2004	2005	2006	2007
Duration (number / value)	2,015 / $161,200	18,539 / $1,483,120 Note 1	2,102 / $165,160	588 / $47,040
Count (number / value)	5,055 / $404,400	7,648 / $611,840	4,291 / $343,280	1,334 / $106,720
Total	7,070 / $565,600	26,187 / $2,094,960	6,393 / $511,440	1,949 / $153,760

Payment numbers and values made under the GSL scheme in the four years of the regulatory control period.

Sources: *Tasmanian Energy Supply Industry Performance Report 2004-05*, issued by the Regulator in December 2005; *Tasmanian Energy Supply Industry Performance Report 2005-06*, issued by the Regulator in December 2006; *Tasmanian Energy Supply Industry Performance Report 2006-07*, issued by the Regulator in December 2007.

Note 1: 17,390 of these payments, totalling $1,391,200, were for outages due to the storms of 3 & 4 February 2005, which were classified as a Major Event Day.

3.4. Non-financial Aspects of the Service Incentive Scheme

The Regulator introduced a range of non-financial measures in the Service Incentive Scheme, with the intention of drawing Aurora's attention to deficient performance by publication of performance data.

As a licence condition, Aurora is required to comply with the reliability performance standards given in section 8.6.11 of the TEC that were applicable for the regulatory control period. Based upon the expected performance improvements resulting from infrastructure expenditure, the Regulator set targets for general feeder performance. There were no financial penalties associated with this aspect of performance monitoring – Aurora reported on a quarterly basis to the Regulator, and the Regulator published the results in the annual ESI Performance Report. More details of this aspect of the Service Incentive Scheme are given in section 4.3.3.2 of the 2003 Final Report.

To ease regulatory concern that Aurora may concentrate on fixing state-wide performance at the expense of local areas, the Regulator implemented a non-financial aspect of the Service Incentive Scheme to monitor and report on local performance. For ease of asset management, Aurora had already divided the state into 19 areas, with each area containing relatively similar terrain and conditions. The areas that Aurora had utilised were:

- 2 CBD areas, being Hobart and Launceston;
- 4 Urban areas, being the suburbs of Hobart and Launceston and all of Devonport and Burnie; and
- 13 Rural areas, which covered all other areas of the state served by Aurora.

Based upon data supplied by Aurora, the Regulator set performance targets for these 19 areas, based upon SAIFI, SAIDI and CAIDI. Aurora reported on a quarterly basis to the Regulator, and the Regulator published the results in the annual ESI Performance Report. More details of this aspect of the Service Incentive Scheme are given in section 4.3.3.1 of the 2003 Final Report.

The Regulator recognised that efficient telephone answering was important from a customer service point of view, but did not consider it necessary to attach financial incentives to fault centre performance during this regulatory control period. The Regulator did, however, require Aurora to report quarterly on Fault Centre performance, with 5% missed calls deemed the minimum acceptable performance. More details of this aspect of the Service Incentive Scheme are given in section 4.3.2 of the 2003 Final Report.

Due to limitations in Aurora's outage management system, MAIFI could not be calculated on less than full feeder outages. While full feeder MAIFI could be reported, calculations were performed manually. Accordingly, the Regulator did not attach any financial penalties to MAIFI, but required Aurora to report quarterly and published the results in the annual ESI Performance Report. More details of this aspect of the Service Incentive Scheme are given in section 4.3 of the 2003 Final Report.

4. Service Incentive Scheme 2008-2012

4.1. Introduction

During his investigation of prices for the regulatory control period commencing on 1 January 2008 and ending on 30 June 2012, the Regulator reviewed the Service Incentive Scheme implemented in the previous regulatory control period. Prior to the Regulator's investigation, the performance standards were revised by a joint working party and accepted by the Regulator for inclusion in the TEC. The state-wide SAIDI and SAIFI targets were removed, being judged inadequate to measure customer-level performance[4] and suffering excessive variability[5].

Following public consultation, the Regulator decided that category and community-based reporting was the appropriate measure to monitor overall performance[6], with the GSL scheme being modified to act as a Service Incentive Scheme[7]. The reporting of feeder performance and feeder category averages was initially retained[8], but was later dropped when the Guideline was reviewed because the information required was picked up in the community reporting.[9] While MAIFI reporting was retained, Aurora can still only report full feeder outages. Additionally, the Customer Charter was reviewed to reflect the revised performance arrangements.

4.2. Performance Standards Review

In 2006/07 the network performance standards were reviewed by a working party comprising representatives of the Office of Energy Planning and Conservation, Aurora and the Regulator's office. These new reliability standards were formed on the principles that it is equitable to have different reliability standards for distinctly different types of communities and that similar communities should receive similar levels of supply reliability. Using this rationale, one hundred and one discrete communities were defined and classified into one of the five community categories. The final report *Joint Working Group Final Report Distribution Network Reliability Standards* in two volumes with 3 appendices of maps was published jointly in February 2007.

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[4] Draft SIS Position Paper, section 5.2

[5] Draft SIS Position Paper, section 5.5

[6] Draft SIS Position Paper, section 6.2

[7] Draft SIS Position Paper, section 6.3

[8] *Electricity Supply Industry Performance and Information Reporting Guideline*, version 1, issued by the Regulator in February 2007

[9] *Electricity Supply Industry Performance and Information Reporting Guideline*, version 1.1, issued by the Regulator in May 2009

The new standards were accepted by the Regulator and incorporated into the TEC in section 8.6.11, to apply from 1 January 2008 (the commencement of the regulatory control period). They provide three separate but related measures of network performance.

The first, most general level is concerned with the five community categories: Critical Infrastructure, High Density Commercial, Urban, Higher Density Rural and Lower Density Rural. Each of these five categories has an associated frequency of outage standard and cumulative outage duration standard. In accordance with the TEC, Aurora is required to use reasonable endeavours to ensure that the frequency of outages for a category, averaged over all communities in that category, and the cumulative duration of outages for a category, averaged over all communities in that category, is less than the appropriate threshold set in the standards.

The second measure of network performance is related to individual communities. In this case, Aurora is required to use reasonable endeavours to ensure that the frequency of outages for a community, averaged over all customers in that community, and the cumulative duration of outages for a community, averaged over all customers in that community, is less than the appropriate threshold set in the standards.

The final measure is GSL payments if service is less than a threshold set by the Regulator – this is discussed in more detail in the next section.

4.3. Guaranteed Service Level Scheme

GSL payments, of which there are two types, are the final measure of network performance in the three tiered model currently in operation in Tasmania.

The first type of GSL payment is for an extended duration single outage, when an installation experiences a single outage of duration greater than a threshold determined by the Regulator: the customer at that installation will then receive a payment from Aurora to recognise that the service received at the installation was considered to be inadequate.

The second type of GSL payment is for when an installation experiences more than a certain number of outages within a twelve-month period: the customer at that installation will receive a payment from Aurora to recognise that the service received at the installation was considered to be inadequate. If, however, an outage was caused by an event manifestly beyond the control of Aurora, Aurora may apply to the Regulator for a determination if the outage is an exempt outage in accordance with the GSL Guideline.

The scheme is run according to the Guideline *Guaranteed Service Level (GSL) Scheme* Version 2 issued by the Regulator in December 2007 (the GSL Guideline).

The threshold values for GSL payments were set by the Regulator based upon historical outage information provided by Aurora[10]. The values of the payments were chosen to place an amount of revenue at risk considered appropriate by the Regulator. That is, the Aurora's GSL liability was equal to the product of the expected number of GSL events and the payment values less the funded amount[11]. The Regulator did not consider it necessary to raise the payment amount. Summaries of the thresholds and payment values for the GSL scheme are given in Table 4 and Table 5; a summary of Aurora's performance under the scheme is presented in Table 6.

The regulator carried over from the previous regulatory control period the range of exemptions: Aurora is not obliged to make payment if the event causing the outage is manifestly beyond the control of Aurora[12]. The Regulator also introduced two methods to control the overall liability of Aurora in the event that considerably more outages attracting GSL payments occurred during the regulatory control period than were forecast. Both of these methods are provided in the 2007 Determination; in consequence they do not apply beyond 30 June 2012.

The first method is designed to recognise staffing difficulties when large events occurred[13]. If more than 34,000 customer suffer outages in a single day, an adjusted duration threshold is calculated. Payments are made to all customers who experiences outages over the standard duration threshold, but half of the difference of payments made to customers between the standard and adjusted thresholds is recovered through adjustments to the AARR in subsequent regulatory years[14].

The second method is a risk-sharing mechanism designed to address the inherent risk of an uncapped GSL scheme: half of any GSL expenditure in excess of a threshold set at twice the allowance over the regulatory period, and tested on a pro rata basis each year, could be recovered by Aurora in the subsequent regulatory year through an adjustment to the allowable revenue[15].

The first method has been utilised once during the regulatory control period: a $256,000 adjustment to the AARR for 2010/11 as a result of the storms of 27 and 28 September 2009. The second method has not been required in the current regulatory control period.

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[10] 2007 Final Report, section 12.4

[11] Draft SIS Position Paper, section 5.10; 2007 Final Report, section 12.4.

[12] See definition of an "exempted outage" in the GSL Guideline.

[13] 2007 Final Report, p232

[14] 2007 Determination, Schedule 1

[15] 2007 Final Report, p232

Table 4 Service Incentive Scheme Multiple Outage Count Thresholds and Payment Value

Category	Threshold: outages per 12 months
Urban, High Density Commercial, Critical Infrastructure	10
Higher Density Rural	13
Lower Density Rural	16
Payment value	$80

Multiple outage count thresholds and payment value for the GSL scheme in operation from 1 January 2008 to 30 June 2012. Reference: GSL Guideline, table 1.

Table 5 Service Incentive Scheme Single Outage Duration Thresholds and Payment Value

Category	Threshold: single outage duration (hours)	
Urban, High Density Commercial, Critical Infrastructure	8	16
Higher Density Rural	8	16
Lower Density Rural	12	24
Payment	$80	$160

Single outage duration thresholds and payment value for the GSL scheme in operation from 1 January 2008 to 30 June 2012. Reference: GSL Guideline, table 2.

Table 6 Numbers and Values of Payments Made Under the Current Service Incentive Scheme

Year ended 30 June	2008*	2009	2010	2011	2012
Extended Duration GSLs					
Short Duration (number / payment)	1,679 / $134,320	7,248 / $582,720	26,463 / $2,117,120	-	-
Long Duration (Number / payment)	183 / $29,280	1,151 / $184,160	14,278 / $2,284,480	-	-
Subtotal	1,862 / $163,600	8,435 / $766,880	40,741 / $4,401,600	-	-
Excessive Count					
(number / payment)	1,245 / $99,600	2,050 / $164,000	3,694 / $295,520	-	-
Total	3,107 / $263,200	10,485 / $930,880	44,435 / $4,697,120		

Number and values of payments made under the Service Incentive Scheme during the current regulatory control period. Sources: Aurora Energy Annual Electricity Distribution Network Performance Report 2007/08, table 6; Aurora Energy Annual Electricity Distribution Network Performance Report 2008/09, table 7; Aurora Energy Annual Electricity Distribution Network Performance Report 2009/10, table 7.

*The first period of the current regulatory control period was of 6 months duration so that regulatory years could change from calendar years to financial years.

4.4. Non-financial Aspects of the Service Incentive Scheme

The Regulator reduced, from the previous regulatory control period, the number of non-financial measures in the Service Incentive Scheme. Nonetheless, the intention remained of drawing Aurora's attention to deficient performance by publication of performance data.

The Regulator was of the opinion that "that reporting on performance against the network reliability standards rather than imposing financial incentives is the most appropriate means available to maintain current average performance without placing inappropriate risks on Aurora or its customers"[16]. Accordingly, Aurora is required by to report quarterly and annually to the Regulator on its performance against the network reliability standards given in section 8.6.11 of the TEC[17], and the Regulator publishes these results in the annual ESI Performance Reports.

Again, the Regulator did not consider it necessary to impose financial performance incentives around the operation of the Fault Centre upon Aurora during the current regulatory period, noting that that quarterly reporting required in the Performance Reporting Guideline was sufficient for regulatory monitoring, especially given the Regulator's ability to investigate large variations in performance[18]. Accordingly, Aurora is required by to report quarterly and annually to the Regulator on the call handling performance of the Faults Centre[19], and the Regulator publishes these results in the annual ESI Performance Reports.

[16] Draft SIS Position Paper, section 6.2

[17] Performance Reporting Guideline, section 7.3

[18] Draft SIS Position Paper, section 7.2

[19] The Performance Reporting Guideline, section 7.3, requires quarterly and aggregated annual reporting of Fault Centre performance

5. Service Target Performance Incentive Scheme 2012-2017

5.1. Introduction

The AER is required by the NER to include a STPIS as component of a building block determination for the provision of standard control services[20] by distributors. To this end, the AER published a Guideline "*Electricity distribution network service providers Service target performance incentive scheme"* (the STPIS Guideline), most recently amended in November 2009, describing the formation and application of the STPIS.

In its application of a STPIS, the AER is obliged to consider jurisdictional GSL schemes and performance targets[21]. The Tasmanian performance standards are contained within the TEC[22]; the Regulator has noted that the performance standards will not be revised, but that the boundaries of the communities may be reviewed to account for community growth. The jurisdictional GSL scheme is provided in the GSL Guideline. It should be noted that the single large event safety net and the risk sharing mechanism of the GSL scheme, the application of which turns the GSL scheme into a *bona fide* Service Incentive Scheme, are provided within the 2007 Determination, which expires on 30 June 2012.

The AER provided an outline of the application of STPIS to Aurora in June 2010 in the document *Preliminary Positions Framework and Approach Paper Aurora Energy Pty Ltd Regulatory Control Period Commencing 1 July 2012* (the Preliminary Positions Paper). In its response to the Preliminary Positions Paper, Aurora noted that it had reservations about the application of the STPIS as outlined by the AER.

The AER has requested that Aurora make a further submission to the AER for consideration outlining Aurora's preferred approach to a STPIS. Aurora's proposal for the STPIS is presented in section 5.3.

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[20] NER, chapter 6, part C

[21] NER, section 6.6.2

[22] TEC, section 8.6.11

5.2. AER Proposed Scheme

5.2.1. Introduction

The AER described its proposal for the application of the STPIS to Aurora in chapter 4 of the Preliminary Positions Paper. The STPIS has, potentially, four components: Reliability of Supply; Quality of Supply; Customer Service; and a GSL scheme, with the first three components contributing to the S-factor that is used to adjust allowable revenues[23]. The STPIS may place a maximum 5% of revenue at risk per annum under an S-factor scheme[24]: the AER has proposed that 5% of Aurora's revenue be at risk[25].

The AER has chosen not to include a Quality of Supply component[26]. The AER's proposed application of the remaining components are discussed below.

5.2.2. Reliability of Supply Component

There are three parameters available to the AER in the Reliability of Supply Component of the STPIS (SAIDI, SAIFI, and MAIFI), with targets for these parameters based on the distributor's historical performance and rates based on the value of customer reliability (VCR) as determined by the AER[27].

The AER has proposed that: [28];

- SAIDI and SAIFI targets be applied to existing categories given in the jurisdictional performance standards with the targets set using historical data consistent with the STPIS guideline;
- the VCR should be $95,700 per MWh for the Critical Infrastructure and High Density Commercial categories and $47,850 per MWh for the Urban, Higher Density Rural and Lower Density Rural categories with the values in September 2008 dollars;
- outages due to load shedding for certain reasons, outages due to failure of the shared transmission network or transmission connection assets (with a caveat), outages due to the exercise of a power under national or local electricity legislation, or outages on Major Event Days be excluded from consideration; and
- Major Event Days be determined using the 2.5β methodology.

In consequence, the maximum revenue at risk for Reliability of Supply Component, taking into account the 0.5% revenue at risk due to the customer service components, is 4.5%.

23 Preliminary Positions Paper, section 4.3.1.

24 STPIS Guideline, section 2.5(a)

25 Preliminary Positions Paper, section 4.7.1.2

26 Preliminary Positions Paper, section 4.3.2

27 Preliminary Positions Paper, section 4.3.2

28 Preliminary Positions Paper, section 4.7.1.4, 4.7.1.5, 4.7.1.6, 4.7.1.7 & 4.7.1.8

5.2.3. Guaranteed Service Level Scheme

The AER notes that it will apply the standard GSL scheme given in the STPIS Guideline only if there is no relevant jurisdictional GSL scheme[29]. There is an existing jurisdictional GSL scheme provided in the GSL Guideline, compliance with which is a licence obligation upon Aurora. The Regulator has indicated to the AER that they do not intend to repeal the Guideline, although they have also indicated to Aurora that they do not intend to codify in the GSL Guideline or the TEC either the large outage safety net or the risk sharing mechanism (see section 4.3 for more discussion on these two methods to control the overall liability under the Service Incentive Scheme). Accordingly, the AER proposes to adopt the GSL scheme given in the GSL Guideline[30].

5.2.4. Customer Service Component

There are four parameters available to the AER in the Customer Service Component of the STPIS (telephone answering, streetlight repair, new connections, response to written enquiries) of which only telephone answering is mandatory[31]. The maximum revenue at risk must be ± 1% of DNSP revenue for each year of the regulatory control period, with no more than ±0.5% at risk for any given component.[32]

The AER has proposed that only the mandatory telephone answering parameter be included and operated as per the SPTIS Guideline, and that the revenue at risk be set at 0.5%.[33]

5.3. Aurora Proposed Scheme

5.3.1. Introduction

Aurora accepts the basic tenets of the AER's proposed STPIS, but suggests that the revenue at risk under the S-factor be reduced to account for the fact that the GSL scheme being implemented was designed as a stand-alone Service Incentive Scheme. The principles of the STPIS proposed by Aurora is discussed below.

5.3.2. Reliability of Supply Component – Network Segmentation

Aurora understands the AER's approach to network segmentation to mean that each of the five categories listed in Table 3 of chapter 8 of the TEC (Critical Infrastructure, High Density Commercial, Urban and Regional Centres, High density Rural, and Lower Density Rural) is considered to be a distinct segment. In consequence, each category will have its own series of SAIDI and SAIFI targets based upon appropriate historical reliability data. Aurora supports the AER's proposed approach to network segmentation.

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29 Preliminary Positions Paper, section 4.3.3

30 Preliminary Positions Paper, section 4.7.4

31 Preliminary Positions Paper, section 4.3.2

32 STPIS Guideline, section 5.2

33 Preliminary Positions Paper, sections 4.7.3.1 & 4.7.3.2

5.3.3. Reliability of Supply Component – Calculation Methodology

The Reliability of Supply Component of the STPIS proposed by the AER is intended to use unplanned SAIDI and SAIFI as the parameters. Further, Appendix A of the STPIS Guideline requires that SAIDI and SAIFI be calculated using customer numbers. Aurora is unable to adequately meet this requirement, as was noted in response to the AER's question in May 2010,

> *Can Aurora clarify whether the reliability of supply (SAIDI, SAIFI and MAIFI3) data is collected in accordance with the AER's definitions of these parameters in the STPIS?,*

Aurora stated in response to this question in the Information Paper for the AER: Services, Classifications and Control Mechanisms Framework and Approach Process provided to the AER in May 2010 that:

> *Aurora does not collect reliability of supply data in accordance with the definitions provided within the AER's definitions of those parameters in the STPIS. It is also important to note that Aurora does not have information on actual customer numbers connected to the distribution network and instead uses connected kVA as a proxy for customer numbers. The methodology prescribed by OTTER also requires a kVA weighting when establishing reliability outcomes for the communities described in the Code.*

The AER has proposed that:

> *SAIDI and SAIFI targets will be calculated for each of these individual categorisations in accordance with reliability of supply data used to calculate GSL payments.*[34]

Aurora notes that the reliability of supply data used to calculate GSL payments is inadequate to set SAIDI and SAIFI targets and monitor performance. The GSL system uses the Aurora "customer to asset link", whereby installations are "linked" to transformers. The customer to asset link is incomplete, being currently between 90% and 95% complete. At the beginning of the five year period required to set performance standards, the customer to asset link project had only just commenced, and was estimated to be 80% complete three years ago. In consequence, any targets set using this data will be wrong to a greater or lesser extent. Aurora contends that it is inappropriate to place any of its annual revenue at risk in a scheme that has poorly set targets.

[34] Preliminary Positions Paper, p98.

On the other hand, the current reliability reporting system monitors outages down to transformer level; that is, the system can identify whether a transformer has experienced an outage and the duration of that outage. The capacity of the transformer (in kVA) is then used in the reliability calculations in conjunction with the outage data. Additionally, the number of customers affected by a transformer outage is generally estimated from the capacity of the transformer assuming that a customer has certain, standard demand. Using this kVA approach, Aurora can confidently provide an outage history back to 2004. On this basis, Aurora proposes that the kVA approach to calculating the SAIDI and SAIFI analogues be continued.

5.3.4. Reliability of Supply Component – Major Event Day Calculations

The AER proposes that Major Event Days be excluded from STPIS calculations and proposes that Major Event Days be identified using the "2.5β" methodology. Aurora supports this approach, although notes that the calculation of SAIDI will be based upon kVA rather than actual customer numbers.

5.3.5. Reliability of Supply Component – Exempt Outages

The AER proposes that the following may be excluded from consideration under the STPIS standard exclusions[35]:

1. load shedding due to a generation shortfall.
2. automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under-frequency condition.
3. load shedding at the direction of the Australian Energy Market Operator (AEMO) or a system operator.
4. load interruptions caused by a failure of the shared transmission network.
5. load interruptions caused by a failure of transmission connection assets except where the interruptions were due to inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning.
6. load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a DNSP.
7. All events that occur on a major event day (MED)where daily unplanned SAIDI for the DNSP's distribution network exceeds the major event day boundary, as set out in appendix D of the STPIS.

Aurora notes that section 14(2) of the ESI Act provides that:

An electricity entity is not obliged to supply electricity to a customer if–

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[35] Preliminary Positions Paper, section 4.7.1.7.

(a) the supply would overload the power system or prejudice in some other way the supply of electricity to other customers; or

(b) the supply would result in contravention of the conditions of the electricity entity's licence; or

(c) the supply would result in risk of fire or some other risk to life or property; or

(d) the supply is or needs to be interrupted–

(i) in an emergency; or

(ii) in circumstances beyond the electricity entity's control; or

(iii) for carrying out work on electricity infrastructure; or

(iv) to comply with a direction to the electricity entity under this Act; or

(e) the electricity entity is exempted from the obligation by regulation.

Aurora contends that the application of these two sets of conditions provides a series of outages that can be considered to be outside of the consideration of the STPIS. In particular, the following are exempted:

- high fire danger days, when Aurora's auto-reclosers are set to lock-out immediately rather than the standard "trip three times then lock-out" by the combination of AER exclusion number 6 and ESI 14(2)(c);
- outages at the direction of emergency personnel by the combination of AER #6 and ESI 14(2)(d)(i);
- 3rd party outages by the combination of AER #6 and ESI 14(2)(d)(ii);
- unplanned outages caused by vegetation originating from outside Aurora's statutory clearance zones by the combination of AER #6 and ESI 14(2)(d)(ii);
- unplanned outages due to most wildlife interactions with Aurora's infrastructure by the combination of AER #6 and ESI 14(2)(d)(ii); and
- outages due to customer installation faults & overloaded service fuses by the combination of AER #6 and ESI 14(2)(d)(ii).

5.3.6. *Reliability of Supply Component – Value of Customer Reliability*

The AER has proposed that the VCR should be $95,700 per MWh for the Critical Infrastructure and High Density Commercial categories and $47,850 per MWh for the Urban, Higher Density Rural and Lower Density Rural categories. Independent evaluation of the methodology used to ascertain the VCR values indicates that the incremental differences between the AER's proposed VCRs and the appropriate values of VCRs for Tasmania given the differences in industry sector mixes are minimal. Accordingly, Aurora supports the use of the AER's proposed values for VCR.

5.3.7. *Customer Service Component*

Aurora supports the AER's proposed approach to application of the Customer Service component of the S-factor scheme.

5.3.8. *Guaranteed Service Level Scheme*

The AER proposes to implement the GSL scheme provided in the GSL Guideline. Aurora notes that only part of the scheme is articulated in the GSL Guideline; the remainder, being the single event safety net and the risk sharing mechanism are provided in the 2007 Determination. While the GSL Guideline has no expiry date, and the Regulator is not intending to repeal the GSL Guideline, the 2007 Determination terminates on 30 June 2012. This termination leaves Aurora with a potentially uncapped GSL liability, which was not the original intention of the Regulator when the scheme was designed (see 4.3 for more discussion of this point).

Aurora supports the AER's proposal to implement the GSL scheme as articulated in the GSL Guideline, but with the following modification: to meet the original regulatory intent inherent in the design of the scheme, but which is lost with the expiry of the 2007 determination on 30 June 2012, the Aurora's GSL liability should be considered in setting the amount of revenue at risk under the S-factor (see section 5.3.9 for more discussion).

5.3.9. *Revenue at Risk*

The AER has proposed that the maximum revenue at risk be applied to Aurora in the STPIS, with 0.5% of annual revenue attached to the Customer Service Component and 4.5% of annual revenue attached to the S-factor.

Aurora notes that this proportion of annual revenue is significantly larger than previously applied in respect of a Service Incentive Scheme. The Regulator placed 1.25% of Aurora's revenue at risk in the regulatory control period from 1 January 2004 to 31 December 2007[36], and a similar amount of total revenue over the current regulatory control period[37]. Aurora contends that such an increase of such magnitude does not adequately consider established jurisdictional regulatory precedent, especially given that the Regulator was aware of the AER's considerations of the appropriate revenue at risk when the Regulator made the 2007 Determination[38] and the Regulator's observation that reporting of category and community performance was sufficient to ensure no loss of reliability[39].

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36 2003 Final Report, section 4.3.1.2

37 2007 Final Report, section 12.4

38 2007 Final Report, section 12.4

39 SIS Draft Position Paper, section 6.2

Aurora notes that the current GSL scheme that the AER proposes to partially implement was designed as a stand-alone Service Incentive Scheme, with an appropriate revenue at risk component. The removal of the single outage safety net and the risk sharing mechanism (see section 4.3) renders the revenue at risk greater than intended. Aurora proposes, therefore, that to recognise the regulatory intent, the revenue at risk associated with the GSL scheme be considered when setting the maximum revenue at risk for the S-factor components of the STPIS.

In particular, Aurora proposes that the revenue at risk be 0.5% of annual revenue attached to the Customer Service Component and that the annual revenue attached to the S-factor be adjusted downwards to account for the historical impact of GSL payments under the scheme that was designed as a stand-alone Service Incentive Scheme and set at a value of a maximum of 2.5%.