AUSTRALIAN COMPETITION TRIBUNAL

Application by SA Power Networks [2016] ACompT 11

Review from:	Australian Energy Regulator
File number:	ACT 11 of 2015
Tribunal:	**MIDDLETON J (PRESIDENT)** **PROFESSOR KT DAVIS (MEMBER)** **MR R STEINWALL (MEMBER)**
Intervener:	South Australian Minister for Mineral Resources and Energy
Date of Determination:	28 October 2016
Catchwords:	**ENERGY AND RESOURCES** – applications under s 71B of the National Electricity Law (NEL) for review of a distribution determination by the AER – consideration of the legislative background to the NEL and the National Electricity Rules (NER) – amendments to the NER made in 2012 by the Australian Energy Market Commission (AEMC) – amendments to the NEL made in 2013 – role of the AER – national electricity objective (NEO) – consultation and notification obligations under s 16(1)(b) – conduct of consultation process under s 71R(1) – relevance of *Applications by Public Interest Advocacy Centre Ltd and Ausgrid* (*Ausgrid*) – topics for review – gamma – return on debt – forecast bushfire safety capital expenditure (capex) – forecast labour cost escalation – forecast inflation **ENERGY AND RESOURCES** – gamma – building block determination – significance of the substitution of “the value of imputation credits” for “the assumed utilisation of imputation credits” in the definition of gamma – valuation of imputation credits – theoretical models – empirical evidence – relevance of the *Ausgrid* decision – proper use of the distribution rate, equity ownership data and tax statistics **ENERGY AND RESOURCES** – return on debt – transition arrangements for the debt risk premium component of the cost of debt – gradual transition compared with immediate transition – allowed rate of return objective – promotion of efficient financing practices – bias in regulatory decision-making – historical data problems – impact of change on benchmark efficient entity and recovery of efficient financing costs – meaning of “across regulatory control periods” – windfall gains and losses

ENERGY AND RESOURCES – forecast bushfire safety capex – capex objectives and criteria – meaning of “regulatory obligation or requirement” – the nature of regulatory obligations – *Electricity Act 1996* (SA) – *Fair Work Act 2009* (Cth) – decisions of AER not to be approached in overly rigid way – compliance with capex criteria

ENERGY AND RESOURCES – forecast labour cost escalation – whether enterprise agreement is a “regulatory obligation or requirement” – operating expenditure (opex) objectives and criteria – capex objectives and criteria – character of enterprise agreements – relevance of the *Ausgrid* decision

ENERGY AND RESOURCES – forecast inflation – post-tax revenue model (PTRM) – building block determination – whether AER can consider inflation outside the PTRM

Legislation:

Australian Energy Market Act 2004 (Cth)
Electricity Act 1996 (SA)
Fair Work Act 2009 (Cth)
National Electricity Rules
National Electricity (South Australia) Act 1996 (SA)
Work Health and Safety Act 2012 (SA)

Cases cited:

Application by ActewAGL Distribution [2015] ACompT 3
Application by ATCO Gas Australia Pty Ltd [2015] ACompT 7
Application by ATCO Gas Australia Pty Ltd [2016] ACompT 10
Application by Energex Ltd (No 4) [2011] ACompT 4
Application by EnergyAustralia and Others [2009] ACompT 8
Application by Jemena Gas Networks (NSW) Ltd (No 2) [2011] ACompT 5
Application by South Australian Council of Social Service Incorporated [2016] ACompT 8
Applications by Public Interest Advocacy Centre Ltd and Ausgrid [2016] ACompT 1
Applications by Public Interest Advocacy Centre Ltd, Ausgrid, Endeavour Energy and Essential Energy [2015] ACompT 2
Toyota Motor Corporation Australia Ltd v Marmara [2014] 222 FCR 152

Date of hearing:	1-2, 4-5 August 2016
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Registry:	South Australia
Category:	Catchwords
Number of paragraphs:	621
Counsel for SA Power Networks:	Mr CA Moore SC with Ms C Dermody and Dr RCA Higgins
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Solicitor for the Australian Energy Regulator:	Australian Government Solicitor

IN THE AUSTRALIAN COMPETITION TRIBUNAL

ACT 11 of 2015

RE:	**APPLICATION UNDER SECTION 71B OF THE NATIONAL ELECTRICITY LAW FOR A REVIEW OF A DISTRIBUTION DETERMINATION MADE BY THE AUSTRALIAN ENERGY REGULATOR IN RELATION TO SA POWER NETWORKS PURSUANT TO CLAUSE 11.60.4 OF THE NATIONAL ELECTRICITY RULES**
BY:	**SA POWER NETWORKS (ABN 13 332 330 749)** Applicant
TRIBUNAL:	**MIDDLETON J (PRESIDENT)** **PROFESSOR KT DAVIS (MEMBER)** **MR R STEINWALL (MEMBER)**
DATE OF DETERMINATION:	**28 OCTOBER 2016**

THE TRIBUNAL DETERMINES THAT:

1. The *Final Decision: SA Power Networks Distribution Determination 2015-16 to 2019-20*, including attachments, is affirmed.

REASONS FOR DETERMINATION

THE TRIBUNAL:

INTRODUCTION

1 This is an application by SA Power Networks ('**SAPN**'), pursuant to s 71B(1) of the Schedule of the *National Electricity (South Australia) Act 1996* (the '**NESA Act**'), for review of a reviewable regulatory decision of the Australian Energy Regulator ('**AER**'), filed with the Australian Competition Tribunal (the '**Tribunal**') on 19 November 2015.

2 The decision under review is the final decision and distribution determination published by the AER on 29 October 2015 pursuant to cl 11.60.4(c) of the NER, entitled 'Final Decision: SA Power Networks Distribution Determination 2015-16 to 2019-20' ('**Final Decision**').

3 On 4 May 2016, SAPN was granted leave to apply for review of the Final Decision, with respect to the designated grounds of review referred to in an amended application for review filed with the Tribunal on 3 May 2016 ('**Review Application**'). The Tribunal's reasons for granting leave are discussed below.

Regulatory regime

4 SAPN is the operator of an electricity distribution network located in South Australia ('**South Australian distribution network**'). SAPN is registered as a distribution network service provider ('**DNSP**') under cl 2.5.1 of the *National Electricity Rules* ('**NER**'), and provides distribution network services by means of the South Australian distribution network.

5 Section 6 of the NESA Act applies the *National Electricity Law* ('**NEL**'), set out in the Schedule of the Act, as a law of South Australia. Section 9 of the NEL gives the NER the force of law in South Australia.

6 Section 7 of the NEL sets out the national electricity objective ('**NEO**'), which is to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers with respect to:

(1) price, quality, safety, reliability and security of supply of electricity; and

(2) the reliability, safety and security of the national electricity system.

7 Section 16(1)(a) of the NEL provides that in performing or exercising an AER economic regulatory function or power, which includes a function or power performed or exercised by the AER relating to the making of a distribution determination, the AER must perform or exercise that function or power in a manner that will, or is likely to, contribute to the achievement of the NEO.

8 Section 16(1)(d) of the NEL provides that if the AER is making a reviewable regulatory decision and there are two or more possible reviewable regulatory decisions that will, or are likely to, contribute to the achievement of the NEO, the AER must:

(1) make the decision that the AER is satisfied will, or is likely to, contribute to the achievement of the NEO to the greatest degree (the '**preferable reviewable regulatory decision**'); and

(2) specify reasons as to the basis on which the AER is satisfied that the decision is the preferable reviewable regulatory decision.

9 In addition, s 16(2)(a) of the NEL requires the AER to take into account the revenue and pricing principles ('**RPP**') when exercising a discretion in making those parts of a distribution determination relating to direct control network services.

10 Section 7A of the NEL sets out the RPP, as follows:

> *(2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in–*
>
> > *(a) providing direct control network services; and*
> >
> > *(b) complying with a regulatory obligation or requirement or making a regulatory payment.*
>
> *(3) A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes–*
>
> > *(a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and*
> >
> > *(b) the efficient provision of electricity network services; and*
> >
> > *(c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.*
>
> *(4) Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted–*
>
> > *(a) in any previous–*
> >
> > > *(i) as the case requires, distribution determination or transmission determination; or*
> > >
> > > *(ii) determination or decision under the National Electricity Code or jurisdictional electricity legislation regulating the revenue earned, or prices charged, by a person providing services by means of that distribution system or transmission system; or*

(b) in the Rules.

(5) A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.

(6) Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.

(7) Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

11 Clause 6.12.1 of the NER provides that a distribution determination is predicated on a number of constituent decisions to be made by the AER. These include:

(1) a decision on the DNSP's building block proposal in which the AER either approves or refuses to approve the annual revenue requirement for the DNSP, as set out in the building block proposal, for each regulatory year of the regulatory control period;

(2) a decision in which the AER either:

(a) acting in accordance with cl 6.5.7(c), accepts the total of the forecast capital expenditure ('**capex**') for the regulatory control period that is included in the current building block proposal; or

(b) acting in accordance with cl 6.5.7(d), does not accept the total of the forecast capex for the regulatory control period that is included in the current building block proposal, in which case the AER must set out its reasons for that decision and an estimate of the total of the DNSP's required capex for the regulatory control period that the AER is satisfied reasonably reflects the capex criteria, taking into account the capex factors;

(3) a decision on the allowed rate of return for each regulatory year of the regulatory control period in accordance with cl 6.5.2;

(4) a decision on the value of imputation credits as referred to in cl 6.5.3; and

(5) any other amounts, values or inputs on which the building block determination is based.

12 Clause 6.12.2 of the NER provides that the reasons given by the AER for a final distribution determination under r 6.11 must set out the basis and rationale of the determination, including:

(1) details of the qualitative and quantitative methods applied in any calculations and formulae made or used by the AER;

(2) the values adopted by the AER for each of the input variables in any calculations and formulae, including:

(a) whether those values have been taken or derived from the provider's current building block proposal; and

(b) if not, the rationale for the adoption of those values;

(3) details of any assumptions made by the AER in undertaking any material qualitative and quantitative analyses; and

(4) reasons for the making of any decisions, the giving or withholding of any approvals, and the exercise of any discretion, as referred to in Ch 6 of the NER, for the purposes of the determination.

13 The exercise of the AER's discretion in making distribution determinations is governed by cl 6.12.3 of the NER.

AER distribution determination process

Impact of the 2012 changes to the NER

14 Section 15 of the NEL prescribes the functions and powers of the AER, which include the making of distribution determinations under the NER.

15 Certain provisions of the NER relating to distribution determinations were amended by the Australian Energy Market Commission ('**AEMC**'), and were published, and took effect from on 29 November 2012 ('**2012 rule changes**').

16 A number of revenue determination processes due to be completed in 2014 and 2015 were delayed through transitional provisions inserted into the NER as part of the 2012 rule changes ('**transitional provisions**'). This delay afforded the AER the time to develop 'Better Regulation' guidelines in response to the 2012 rule changes (the '**Better Regulation Guidelines**'). The Better Regulation Guidelines were published in late 2013.

17 Key aspects of the transitional provisions applying to SAPN's distribution determination process are as follows:

(1) the date for submission of SAPN's regulatory proposal was delayed by nine months, from 31 January 2014 to 31 October 2014;

(2) the AER was not required to publish a draft distribution determination in relation to SAPN's regulatory proposal, as it would have been required to do under cl 6.10.1 of the NER, in the absence of the transitional arrangements. Rather, following appropriate consultation on SAPN's regulatory proposal, the AER was able to proceed immediately to making a distribution determination under cl 6.11.1 of the NER;

(3) at the same time as the AER published its distribution determination under cl 6.11.1 of the NER (which it was required to by 30 April 2015), it was required to also publish an invitation for written submissions on the revocation and substitution of that distribution determination;

(4) under cl 11.60.4(b) of the NER:

(a) any person was allowed to make a written submission to the AER in relation to the revocation and substitution of the distribution determination within the time period specified by the AER, which must not be earlier than 45 business days after the making of that distribution determination; and

(b) without otherwise limiting the manner in which SAPN's may make such submissions, SAPN was allowed to make a submission in the form of revisions to the regulatory proposal that it submitted to the AER in relation to the distribution determination that was to be revoked.

(5) by no later than 31 October 2015, the AER was required to revoke its distribution determination for the 2015-2020 regulatory control period and make a new distribution determination in substitution for the revoked determination which takes effect as at the date it is made; and

(6) in making the new distribution determination, the AER was required to have regard to:

(a) the matters it would be required to have regard to if it were making a final distribution determination under "current Chapter 6" subsequent to it making a draft distribution determination that is the same as the revoked determination including (except where (c) below applies) the regulatory proposal that was submitted to the AER in relation to the revoked determination;

(b) written submissions received in relation to the revocation and substitution of the distribution determination;

(c) any revisions to the regulatory proposal that was submitted to the AER in relation to the revoked determination and that are given to the AER under cl 11.60.4(b); and

(d) any analysis undertaken by or for the AER that is published prior to the making of the distribution determination or as part of the distribution determination.

SAPN's regulatory review process

18 Pursuant to cl 6.8.2 of the NER (as modified by cl 11.60.3 of the transitional provisions), SAPN was required to submit, and on 31 October 2014 did submit, a regulatory proposal to the AER for consideration in accordance with the NER ('**Regulatory Proposal**').

19 On 30 April 2015, pursuant to cl 6.11.1 of the NER, the AER published a decision and distribution determination entitled 'Preliminary Decision: SA Power Networks Distribution Determination 2015-16 to 2019-20' ('**Preliminary Decision**').

20 On 3 July 2015, pursuant to cl 11.60.4(b) of the NER, SAPN submitted a revised regulatory proposal to the AER for consideration in accordance with the NER ('**Revised Proposal**').

21 On 29 October 2015, the AER published its Final Decision, pursuant to cl 11.60.4(c) of the NER.

22 On 19 November 2015, SAPN filed an application for leave and review under s 71B of the NEL.

LEAVE TO APPLY FOR REVIEW

23 Section 71B of the NEL provides:

71B – Applications for review

(1) An affected or interested person or body, with the leave of the Tribunal, may apply to the Tribunal for a review of a reviewable regulatory decision.

(2) An application must—

(a) be made in the form and manner determined by the Tribunal; and

(b) specify the grounds for review being relied on.

24 The Tribunal accepts that, for the purposes of s 71B(1) of the NEL:

(1) SAPN is an "affected or interested person or body" (as that term is defined in s 71A of the NEL); and

(2) the Final Decision, the decision that is under review in the present application, is a reviewable regulatory decision, as it is a network revenue or pricing determination that sets a regulatory period.

25 In addition, it is accepted that there is no issue that SAPN's application for review was made within the 15 business-day time limit prescribed by s 71D of the NEL.

26 The application for leave to apply for review was unopposed by the AER.

27 As previously mentioned, on 4 May 2016, SAPN was given leave to apply for review of the Final Decision on the grounds set out in its Review Application.

28 It is worth noting that the South Australian Council of Social Service ('**SACOSS**') also applied for leave to review the Final Decision, however the Tribunal dismissed SACOSS' application for review on 2 May 2016: see *Application by South Australian Council of Social Service Incorporated* [2016] ACompT 8.

Requirements for the leave application

29 Section 71C of the NEL sets out the following two relevant requirements for applications made under s 71B of the NEL:

71C – Grounds for review

(1) An application under section 71B(1) may be made only on 1 or more of the following grounds:

(a) the AER made an error of fact in its findings of facts, and that error of fact was material to the making of the decision;

(b) the AER made more than 1 error of fact in its findings of facts, and that those errors of fact, in combination, were material to the making of the decision;

(c) the exercise of the AER's discretion was incorrect, having regard to all the circumstances;

(d) the AER's decision was unreasonable, having regard to all the circumstances.

(1a) An application under section 71B(1) must also specify the manner in which a determination made by the Tribunal varying the reviewable regulatory

> *decision, or setting aside the reviewable regulatory decision and a fresh decision being made by the AER following remission of the matter to the AER by the Tribunal, on the basis of 1 or more grounds raised in the application, either separately or collectively, would, or would be likely to, result in a materially preferable NEO decision.*

30 It is worth repeating that, pursuant to s 7 of the NEL, the NEO is to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers with respect to:

(1) price, quality, safety, reliability and security of supply of electricity; and

(2) the reliability, safety and security of the national electricity system.

31 The Tribunal accepts that SAPN's Review Application was made only on the grounds of review specified in s 71C of the NEL.

32 The Tribunal has reached that conclusion having regard to the observations made in recent Tribunal decisions relating to applications for limited merits review by DNSPs in NSW and ACT. For example, the Tribunal accepts that:

> *… the line between the several available grounds of review is not necessarily always clear cut. Sometimes, it will be a clear line, and sometimes it will not. Moreover, there is no prescription in s 71C that, in particular facts and circumstances, there can be only one ground of review made out …*
>
> *There is also no clear line between factual error, opinion, and discretionary judgment; one may feed into the other.*
>
> *… error or errors – if accepted – may be a combination of error or errors of fact, wrongful exercise of discretion, and/or the outcome of an unreasonable decision. Because the characterisation of error or errors, if made out, will more clearly emerge in the course of considering the review related material and the submissions dealing with it, the Tribunal does not consider it appropriate or necessary to embark upon the careful textual analysis and criticism of the* [DNSP's] *application at this point to describe the combination or permutation of alternative expressions of reviewable error in that application.*

See *Applications by Public Interest Advocacy Centre Ltd, Ausgrid, Endeavour Energy and Essential Energy* [2015] ACompT 2 at [55], [57]; *Application by ActewAGL Distribution* [2015] ACompT 3 at [21].

33 Further, the Tribunal has had regard to the matters outlined in SAPN's submissions on its application for leave to review ('**Leave Submissions**') and paragraphs [22]-[26] and [200]-[210] of SAPN's Review Application. In considering these matters, the Tribunal accepted, in granting leave to apply for review, that SAPN had sufficiently addressed the manner in which

a determination by the Tribunal in accordance with s 71C(1a) of the NEL may result in a materially preferable designated NEO decision.

Criteria for the grant of leave

34 Pursuant to s 71E of the NEL, the Tribunal must not grant leave to apply for review unless it appears to the Tribunal that:

> *(a) that there is a serious issue to be heard and determined as to whether a ground for review set out in section 71C(1) exists; and*
>
> *(b) that the applicant has established a* prima facie *case that a determination made by the Tribunal varying the reviewable regulatory decision, or setting aside the reviewable regulatory decision and a fresh decision being made by the AER following remission of the matter to the AER by the Tribunal, on the basis of 1 or more grounds raised in the application, either separately or collectively, would, or would be likely to, result in a materially preferable NEO decision.*

35 However, even where the Tribunal determines that the criteria in s 71E are satisfied, leave to apply under s 71B must not be granted "unless the amount that is specified in or derived from the decision exceeds the lesser of $5,000,000 or 2% of the average annual regulated revenue of the regulated network service provider": s 71F(2) of the NEL.

36 The Tribunal may also refuse to grant leave on the grounds set out in s 71H(2) of the NEL, namely that:

> …
>
> *(a) without reasonable excuse—*
>
> > *(i) failed to comply with a request (including a request for relevant information), or a direction, of the AER made under this Law or the Rules for the purpose of making the decision; or*
> >
> > *(ii) conducted itself in a manner that resulted in the making of the decision of the AER being delayed; or*
>
> *(b) misled, or attempted to mislead, the AER on a matter relevant to the AER's decision.*

37 There is no suggestion, however, by the AER or SAPN that any of the conditions contained in that provision are present to enliven the Tribunal's discretion to refuse the granting of leave.

38 Each of the relevant criteria for leave in s 71E and s 71F(2) of the NEL are considered below.

Financial threshold (s 71F(2) of the NEL)

39 The affidavit of Luke Woodward affirmed on 19 November 2015, and made in support of SAPN's Review Application sets out the 2% of the average annual regulated revenue of SAPN over the 2015-2020 regulatory control period specified in or derived from the Final Decision as approximately $15.9 million. As such the relevant threshold pursuant to s 71F(2) is $5 million.

40 As previously held by the Tribunal in *Application by Energex Ltd (No 4)* [2011] ACompT 4 ('***Energex (No 4)***'):

(1) the "amount that is specified in or derived from the decision" should not be read literally as meaning the total revenue to be derived by the service provider, rather, the amount at issue in light of the grounds upon which the AER's decision is challenged: *Energex (No 4)* at [50]; and

(2) when determining whether the financial threshold in s 71F(2) of the NEL is satisfied, all of the errors are to be taken into account; the threshold does not need to be satisfied for each ground: *Energex (No 4)* at [52]; see also *Application by Jemena Gas Networks (NSW) Ltd (No 2)* [2011] ACompT 5 at [3]; *Application by ATCO Gas Australia Pty Ltd* [2015] ACompT 7 at [21] ('***ATCO* 2015**').

41 SAPN's Leave Submissions set out the relevant amounts specified in or derived from the decision in respect of each of the topics that are the subject of grounds for review in SAPN's Review Application. On the basis of these amounts, the Tribunal considered that the financial threshold was comfortably satisfied.

Serious issue to be heard and determined (s 71E(a) of the NEL)

42 SAPN adopted the submissions of Ausgrid, Endeavour Energy, and Essential Energy in *Applications by Public Interest Advocacy Centre Ltd, Ausgrid, Endeavour Energy and Essential Energy* [2015] ACompT 2, in relation to the legal principles relevant to the meaning of "serious issue to be heard and determined". These submissions were accepted in *ATCO* 2015 at [23], where the following principles were noted as being of particular relevance:

> *(a) The phrase 'serious issue to be heard and determined' has been correlated with the phrase 'serious question to be tried' in the context of the grant of interlocutory injunctions:* Re Application by ElectraNet Pty Limited *[2008] ACompT 1 at [39]-[42];*

> (b) *The relevant question is indeed whether an applicant has established that there is a serious issue to be heard and determined given the nature of the rights asserted by the applicant and 'the practical consequences likely to flow' from the grant of leave. In particular, the Tribunal has previously expressed the view that the threshold merely requires the applicant to 'show that there is a sufficient prospect of success to justify in the circumstances it being given the opportunity' to have the decision reviewed:* Application by Envestra Ltd *[2011] ACompT 12 at [21].*

43 SAPN made extensive submissions on whether there was a serious issue to be tried in respect of:

(1) gamma

(2) allowed rate of return – return on debt

(3) forecast inflation;

(4) forecast bushfire safety capex;

(5) forecast labour cost escalation;

(6) operating expenditure ('**opex**') for increased asset inspections in bushfire risk areas; and

(7) opex for "no access" poles inspections.

SAPN ultimately decided not to apply for review of the final two topics above relating to opex.

44 For each of these topics, SAPN set out the background to the issue, summarised the issue as arising in SAPN's Regulatory Proposal and in the AER's Final Decision, and identified the specific aspects of the relevant grounds of review to demonstrate that there was a serious issue to be heard and determined.

45 As will be apparent from the reasons in respect of each ground of review below, there were serious issues to be heard and determined on SAPN's Review Application.

Prima facie case on materially preferable NEO decision (s 71E(b) of the NEL)

46 For each of the issues in dispute, SAPN made submissions on how rectification of an error in the AER's distribution determination – if found to be an error – could result in a materially preferable NEO decision. SAPN then submitted in its Leave Submissions at [241]:

> *The immediate consequence of these errors is that the overall revenue allowance determined by the AER in its Final Decision is materially below that which would be required by an efficient entity to recover at least efficient costs and provide a commercial market return to investors across the 2015-20 regulatory control period.*

> *As noted in paragraphs 198 and 199 of the SA Power Networks Application, these are individually material in terms of the overall regulated revenue SA Power Networks is permitted to earn, and in aggregate are very significant – that is, approximately, a $285.6 million ($nominal) revenue reduction.*

47 Further, SAPN also submitted that if the Final Decision is left uncorrected:

(1) SAPN's incentives and signals to undertake investment in the network and operations would be distorted due to a significant revenue shortfall;

(2) the shortfall in the allowances for the operating and capex may lead to an inability to recover the efficient costs of meeting regulatory (or otherwise appropriate) safety obligations and requirements of the distribution system;

(3) perceptions of regulatory risk will significantly increase; and

(4) it will set a precedent (in the non-technical sense of that term) for under-compensation of SAPN (and potentially other businesses) now and in the future.

48 The Tribunal considered SAPN's submissions in this respect. The Tribunal was satisfied that SAPN has made a prima facie case in accordance with s 71E(b) of the NEL.

49 On the basis of the above considerations, and as will be apparent further from the reasons in respect of each of the topics below, the Tribunal considered it was appropriate to grant leave to SAPN to apply for review.

COMMUNITY CONSULTATION PROCESS

50 The consultation process referred to in s 71R(1)(b) of the NEL is an additional procedural step which the Tribunal must take and, ideally, be accommodated within the target time prescribed by s 71Q of the NEL.

51 The Tribunal, having given leave to SAPN to apply for review in this matter on 4 May 2016, sought information from the AER as to groups or persons who might have an interest in the Tribunal's review under s 71R(1)(b) of the NEL.

52 The Tribunal then conducted an extensive communication process with each of those groups or persons, to invite them to indicate:

(1) whether they wished to consult with the Tribunal in relation to the Final Decision;

(2) the nature of their proposed participation; and

(3) how the consultation might best be carried out.

53 Having determined a protocol for the consultation, the Tribunal issued a Consultation Agenda under which it provided for those who wished to speak to the Tribunal on that occasion either personally or on behalf of an organisation, to do so.

54 The Tribunal conducted the consultation on 1 June 2016 at the Federal Court of Australia in Adelaide. As there was time remaining at the end of the consultation, opportunity was also provided for those who had not registered to participate, to make submissions to the Tribunal.

55 The transcript of that consultation process has been included by the Tribunal on its website. The following is a list of the entities and their representatives who made submissions during the consultation process, or in writing as a complement or supplement to oral submissions, or by providing written submissions after the consultation:

(1) National Irrigators' Council – Tom Chesson (Chief Executive Officer)

(2) Central Irrigation Trust – Gavin McMahon (Chief Executive Officer)

(3) UnitingCare Australia and Uniting Communities – Mark Henley (Manager Advocacy and Communications)

(4) Business SA – Andrew McKenna (Senior Policy Adviser)

(5) Riverland Energy Association – Brenton Paige (Association Member)

(6) SACOSS – Jo De Silva (Senior Policy Officer)

(7) The South Australian Financial Counsellors Association – Wendy Shirley (Executive Officer)

(8) Riverland Wine – Chris Byrne (Executive Officer)

(9) Major Energy Users, Inc, acting for Energy Users Coalition of SA – David Headberry (Public Officer)

(10) South Australian Chapter of The Electric Energy Society of Australia – Martyn Pearce (Chairman)

(11) Jubilee Almonds and Century Orchards – Brendan Sidhu (Chief Executive Officer)

(12) The Better Drinks Co Pty Ltd – Kym Baldock (General Manager)

(13) Renmark Irrigation Trust – Barry Schier (General Manager)

(14) Energy Consumers Australia – Rosemary Sinclair (Chief Executive Officer)

(15) Consumer Utilities Advocacy Centre

(16) Bundaberg Regional Irrigators Group

56 All submissions at the consultation were made on behalf of organisations. For ease of reference, the contributions will be identified according to the organisation, rather than the organisation's representative.

57 SAPN, the AER and the South Australian Minister for Mineral Resources and Energy (the '**Minister**') as intervener did not participate in the consultation process. That was appropriate, of course, because they each participated in the hearing before the Tribunal.

58 In the course of the consultation, a number of issues of concern to consumers and consumer interests were identified and the participants' submissions fell into several broad themes. It is, in the view of the Tribunal, helpful to summarise the submissions made in relation to the major themes, as identified by the Tribunal. It is important to note that neither the entirety of the submissions, nor every topic raised will be captured, and the broad themes as identified by the Tribunal will only be in summary form.

59 It is useful to note the starting point from which the majority of the submissions were made. It was generally submitted that, when considered according to the elements of the NEO – price, quality, safety, reliability and security of supply of electricity – the only element with which consumers were dissatisfied was price. As the Bundaberg Regional Irrigators Council ('**BRIG**') submitted:

> *In terms of the elements of the NEO, BRIG believes that price is the most important and has the greatest impact on consumers and their long term interests. Price has been neglected in favour of investment in recent determinations.*

60 Similarly, in survey of businesses conducted by Business SA, 87% of responses ranked reduction in electricity prices as most important, with less than 1% ranking it as either the lowest, or second lowest priority.

61 While each of the topics for review were referred to at the consultation, those that received most attention were gamma and taxation, forecast bushfire safety capex, and forecast labour cost escalation.

Impact on local industry, businesses and the local community

62 The majority of the participants drew connections between the cost of electricity and its impact on the relevant industry and the broader community. One of the key messages of participants was the importance of agriculture in South Australia, and therefore, the region's dependency on irrigation and electrical energy to operate irrigation for agricultural purposes.

Participants impressed upon the Tribunal the centrality of the agricultural industry to the region's prosperity, and therefore the importance of its protection into the future. As was submitted by The Better Drinks Co Pty Ltd, the whole Riverland region relies on what is pumped out of the river and therefore it affects all industries in the area. Participants also submitted that with other local industries, such as manufacturing, shrinking, more pressure was placed on agricultural industries to keep the local economy healthy.

63 The participants identified specific ways in which the cost of electricity impacted not only on their own businesses but also more broadly on the local industry and, as a result, the local community. For example, Central Irrigation Trust submitted that to absorb the higher costs of electricity, the business were required to either run down assets or reduce opex or capex. National Irrigators' Council submitted that, for many businesses, the only place that increasing electricity prices could be "worn" was in reducing the number of employees of the business. This had the ripple effect on households, already struggling with "some of the world's highest energy prices", which necessarily had to reduce their spending at local shops and restaurants, in turn harming the other local industries. Similarly, BRIG submitted that:

> *The intentional optimization and deliberate gaming of network profitability has resulted in a rate of price escalation that is unethical and is harming business and domestic consumers across the NEM with standards of living suffering appreciably and less money available for reinvestment in our farms.*

64 While a number of participants outlined the measures they were taking to manage increasing electricity prices, improve efficiency and remain competitive, several participants noted that electricity prices were something beyond the consumers' control. South Australian Financial Counsellors Association ('**SAFCA**') submitted that the steep increase in electricity prices during the previous regulatory period had not been matched by the community's capacity to pay.

65 A number of participants described the "Swiss cheese" effect of increased electricity prices, being that higher electricity prices were forcing some consumers to seek alternative sources of energy "off the grid". In the long run however, this would mean fewer consumers to pay for the network. It was in this context that participants submitted that from a policy perspective, increasing electricity prices which drove consumers away from the grid seemed an "absurd" strategy for SAPN itself.

Competition in international and domestic markets

66 Several participants addressed the Tribunal on how increasing electricity prices, and energy costs in general, had, and would continue to undermine the competitiveness of South Australian businesses if something was not done to address them. The high export rate of produce from irrigated agriculture in South Australia meant that the almond, wine and juice producers were competing with producers from Chile, Argentina, South Africa, North America and across Europe. Therefore, to continue to be a significant wealth generator for South Australia, agriculture producers would have to remain competitive both domestically and internationally.

67 For businesses such as The Better Drinks Co Pty Ltd, which operated in a highly competitive market both domestically and internationally, it was submitted that there was a very limited ability to pass on increased costs to its customers, and so the increase in costs had to be absorbed by business itself. Central Irrigation Trust submitted that Australia's competitive advantage was being quickly squandered through rising energy costs. Business SA submitted that the pending structural change on South Australia's economy with the exit of the automotive manufacturing industry in 2017 provided further impetus for energy costs to not contribute to an already uncompetitive cost base, compared with interstate and international competitors.

Long term interests of the consumer

68 The notion of the "long term interests of consumers" ('**LTIC**'), as the factor underpinning the NEO, was a focal point of many of the submissions. In considering the factors relevant to the LTIC, UnitingCare Australia and Uniting Communities ('**UnitingCare**') sought to juxtapose the "supply-side" perspective of the LTIC contended for in SAPN's Review Application with the "demand-side" perspective of network users. Therefore, it was submitted that the elements of the LTIC, as specified in the NEO, should be interpreted in the following way:

- *Price* – end consumer pays no more than is necessary;
- *Reliability* – all consumers are able to afford to pay for the essential use of electricity needed to participate in contemporary society, and that people will not be cut off from electricity supply for essential purposes because it is too expensive;
- *Quality* – prices as well as supply are stable with no supply-side or bill shocks;

- *Safety* – a person's house is not at risk of burning down because they cannot use electricity for safe lighting, cooking or heating or other unsafe practises considered in the absence of supply.

69 Energy Consumers Australia ('**ECA**') also directed some of their submissions to considering the appropriate interpretation of LTIC. ECA submitted that the question for interpretation is whether "efficiency" is the goal, and LTIC is just a signpost to balancing items, or whether LTIC is the goal, and efficiency is the means to achieve it. In developing its interpretation, ECA submitted that the objective of the regulatory regime is to deliver the outcomes that are equivalent to those that would be delivered if there were competition achieved in the electricity market. ECA identified such outcomes as the consumer interests, price, quality, safety, reliable and secure supply services – in essence, the elements of the NEO, through which the LTIC must be achieved.

Impact on SAPN

70 Some of the participants submitted that SAPN's Regulatory Proposal would ultimately work against SAPN's interests as it would force a significant proportion of consumers off the grid through increased prices. This would thereby reduce SAPN's customer base and impact on its ability to run its business. A number of participants noted that they were investigating alternative energy sources to run their businesses such as through diesel generation and solar energy.

Taxation and gamma

71 An issue raised by a number of the participants at the consultation was the amount of tax paid by SAPN. Many consumers called for an explanation for why consumers were paying for an income tax equivalent of "over $400 million" when, as the participants submitted, it did not appear to reflect the amount of tax SAPN was actually paying. As UnitingCare submitted, the Consumer Challenge Panel (established by the AER to assist with the AER's regulatory determinations) noted that SAPN has historically paid minimal tax to the Australian government despite increases in the regulatory revenue allowance from 2011. UnitingCare emphasised that it was not suggesting anything improper on the part of SAPN. However, it raised the issue to ensure consumers were not paying more as a result of a "more-than-generous" credit arrangement in favour of SAPN.

72 In seeking clarity and transparency around the amount of tax paid by SAPN, the participants also called for an indication of taxation allowances for privately owned distributors to determine whether this properly represented their actual tax costs. In support of this submission, National Irrigators' Council referred to the Minister's criticism of SAPN for making "super profits" from its customers.

73 Consumer Utilities Advocacy Centre ('**CUAC**') considered the relationship between gamma and the LTIC in two respects. First, submitting that the value for gamma proposed by SAPN "relies on a single methodology that produces statistically unstable results because it is highly sensitive to underlying assumptions", CUAC urged the Tribunal to consider

> *whether it is in the best interests of consumers for the regulator to rely on this single measure and methodology, rather than considering a wider range of evidence drawn from different methodologies to produce a more robust value for gamma, as has been done by the AER in their guideline paper.*

74 Secondly, CUAC noted the recent changes in the NEL, as stated in the second reading speech of the Statues Amendment (National Electricity and Gas Laws – Limited Merits Review) Bill 2013, which sought to ensure

> *consumers do not pay more than necessary for the quality, safety, reliability and security of supply of electricity and natural gas under the national energy laws.*

75 However, CUAC queried how this would be reflected and implemented if SAPN's own estimate of their proposed gamma value would cost consumers $85.2 million over the 2015-2020 period.

76 Central Irrigation Trust submitted that the effect of the AER's determination in the Final Decision in respect of gamma was viewed to be a transfer of money from their own business to SAPN. Renmark Irrigation highlighted that even small changes in the value of gamma would mean "big returns" for SAPN. It was considered to be in the best interests of consumers for the AER's gamma methodology to be ratified by the Tribunal.

77 Major Energy Users ('**MEU**') considered gamma in the context of the incentive nature of the regime. MEU submitted that not only have companies been willing to invest in SAPN with a gamma of 0.5 or 0.4 over many years, but it was also submitted that the current owner of SAPN was prepared to invest in the distributor with a gamma of 0.4. It followed, on MEU's submission, that there was no reason to change it as a disincentive could not be identified.

Capex and opex

78 In raising issues about the specific topics for review, a number of participants voiced concerns about capex and opex generally.

79 Business SA submitted that a broad concern was that substantial increases in the AER's determination both in relation to capex and opex will lock in significant additional electricity costs over the next five years and beyond, as they would be incorporated into the regulatory asset base and opex used in future calculations. It was further submitted by Business SA that it considered it to be "inconceivable" for capex and opex to be increasing as it submitted that the demand on the electricity network was static, if not in decline. More fundamentally, SACOSS expressed concern that SAPN was attempting to expand the meaning of its regulatory obligations to justify additional expenditure in relation to capex and opex.

80 Drawing a connection with the concern around consumers abandoning the network in favour of alternative energy sources, Riverland Energy Association posed the question of who would be paying for existing and new assets proposed by SAPN if future customers would be seeking alternative energy sources and deserting the traditional network supply base.

Forecast bushfire safety capex

81 One of the main issues raised by participants at the consultation in relation to the bushfire mitigation capex was the absence of legislative changes by the South Australian government to warrant or require SAPN's increase in spending on bushfire mitigation over the relevant regulatory period. SACOSS submitted that the AER was correct to conclude that the regulatory obligations imposed by *Electricity Act 1996* (SA) ('**Electricity Act**') and *Work Health and Safety Act 2012* (SA) ('**WHS Act**') in relation to the bushfire mitigation measures had not been expanded by the outcome of the Victorian Bushfire Royal Commission and Powerline Bushfire Safety Taskforce, as had been suggested by SAPN. Further, SACOSS submitted that, in any event, SAPN had failed to demonstrate how the additional expenditure proposed in their Regulatory Proposal was prudent and efficient. Similarly, MEU emphasised that the amount allowed for bushfire mitigation capex should not simply be the cost of service but what is efficient.

82 Business SA submitted that as SAPN's proposal on bushfire mitigation capex had been made independent of comprehensive policy consideration, it did not represent optimal public policy outcomes. Participants warned against allowing SAPN to become an "arbiter" on what

constitutes good industry practice in relation to bushfire mitigation, and disregarding the AER's views on the basis that is "merely" an economic regulator. MEU submitted that such an approach would risk shifting from an incentive-based regime, which was specifically required by the legislation, to a regime driven by cost of service.

83 A contrasting perspective was provided by the South Australian Chapter of the Electricity Energy Society of Australia ('**EESA**'). EESA acknowledged that SAPN had been achieving good results in bushfire mitigation controls. However, EESA submitted that SAPN, with whom lay a large portion of the responsibility for protecting the community during bushfires, had to demonstrate continuous improvement to its practices to address "reasonably foreseeable" events causing bushfires. Otherwise, as EESA submitted, such organisations would become vulnerable to litigation, particularly in light of the findings and changes brought about in this sphere following the Victorian Bushfires Royal Commission. It was submitted that the cost of litigation in circumstances where negligence and the "reasonable foreseeability" test were made out, would be in excess of $12 million. In light of this, and the public expectation that EESA considered existed for such measures to be implemented, EESA contended for the program of bushfire mitigation proposed by SAPN to be approved.

Forecast labour cost escalation

84 Forecast labour cost escalation received significant attention during the consultation. Participants submitted that SAPN's proposal to increase the terms of the enterprise bargaining agreement ('**EA**' or '**EBA**') governing SAPN's employees was at odds commercially with other EAs across Australia, particularly in light of what were considered to be already favourable EA terms. A number of participants queried why increases in allowances for labour costs would be required where there had been no indication of increases in productivity. As CUAC submitted:

> *It is questionable whether any increases in real labour price growth are appropriate – and in the long term interests of consumers – without a corresponding increase in productivity growth. As stated by in the* [Victorian Energy Consumer and User Alliance] *submission, "productivity and labour price increases are inextricably linked". This is particularly pertinent given that the AER has accepted the networks in both states have proposed zero productivity growth (with the exception of Jemena in Victoria), despite the significant capital expenditure over the previous period. CUAC notes that SAPN proposed that the AER adopt negative productivity growth forecasts in its alternative estimate of opex.*

85 Business SA submitted that while the shareholders in SAPN were free to remunerate their labour force as they saw fit, electricity consumers would not be willing to absorb any costs considered above the efficient rate in relation to market conditions in South Australia.

86 SACOSS noted its support for the AER's decision to use the wage price index to escalate cost rather than basing the escalation on SAPN's EA. MEU identified the risk with allowing SAPN to determine the escalation, rather than using an external benchmark: there would be no competitive pressure on SAPN to negotiate an EA on terms most favourable to consumers. This is particularly the case given that, as MEU submitted, without an external competitor, the unions, with whom SAPN would be negotiating, could argue that the business could just pass on its costs to clients.

87 SACOSS further submitted that, if an error in the AER's decision were identified, the Tribunal should still consider whether, in any event, it would be a materially preferable NEO decision to reverse the AER's decision when the reviewable regulatory decision was considered as a whole.

Consumer engagement

88 The 2012 rules changes required DNSPs to improve their engagement with electricity consumers to ensure that capex and opex forecasts include expenditure to address consumers' concerns. The consumer engagement process ('**CEP**') conducted by SAPN received some criticism from participants. Riverland Energy Association contended that the "cornerstone" of SAPN's Review Application was based on the AER failing to giving significant weighting to the views of the consumer expressed in SAPN's CEP. However, Riverland Energy Association identified the methods adopted by SAPN for determining the consumers' priorities to be self-fulfilling "in the extreme". SACOSS claimed, both at the consultation and in written submissions filed with the Tribunal subsequently, that as the CEP undertaken by SAPN was conducted in respect of areas not the subject of review before the Tribunal, it should be not be relied upon by SAPN to demonstrate the LTIC, nor be given any weight in the Tribunal's considerations in this review. SACOSS submitted that its only relevance was to highlighting the consumer concern about potential cost increases, and directed the Tribunal's attention to SAPN's research findings relating to the consumers' willingness to pay, namely that:

> *there is significant community concern about potential cost increases. Half of the customers surveyed are very concerned about the prospect of rising electricity costs.*

89 MEU also identified problems with consumer engagement in the regulated energy distribution sphere more generally. For example, it was claimed that there was insufficient time to engage with consumers, consumers had inadequate knowledge to be able to make an informed contribution or recommendation, and the majority of time spent engaging with consumers was explaining the role of a network distributor, and distinguishing it from a network retailer. MEU considered this to be detracting from a discussion of the substantive issues.

Role of the Tribunal and the regulatory process

90 Participants also addressed the Tribunal on their perceptions of the regulatory process and what they considered to be the role of the Tribunal in the process.

91 A number of participants articulated that they saw the Tribunal as a "final backstop for consumers." One participant "challenged" the Tribunal to bring electricity prices in South Australia back to the bottom quartile of prices amongst countries forming the Organisation for Economic Co-operation and Development ('**OECD**'). SAFCA submitted that for the Tribunal to achieve the materially preferable NEO decision, it is required to take into account real-life experiences of large numbers of low and modest income households.

92 Some comments were made about the regulatory process more generally. Some participants submitted that they felt let down by the regulatory process given the sharp rise in SAPN tariffs over the last regulatory period. UnitingCare submitted that consumer behaviour over recent years put paid to the notion that regulation of network monopolies successfully functioned as a proxy for competitive and efficient markets. UnitingCare cited a number of statistics to support this argument, including that:

- 31,666 South Australian households had an electricity debt, with the average debt being $758;
- 3,174 South Australian small businesses had an electricity debt, with the average debt being $1,559; and
- South Australia has highest rate of energy customers on hardship programs.

93 BRIG also expressed their dissatisfaction with the regulatory process:

> *The network price setting process is deeply flawed. In BRIG's experience, it has been a one sided process that has no regard for impact on consumers or the wider economy. If the AER's increased powers are greatly reduced by the decisions of this Tribunal, we fear this will continue to be the case.*

94 In relation to the regulatory review process, participants submitted that they considered it to be adversarial, intimidating and complex. Others noted that as it took significant time to understand the technical and complex concepts such as theta, gamma, and regulatory asset bases, the process itself became costly and time consuming for businesses to participate in it effectively.

95 The incentive-focus of the regulatory regime was also raised as an issue. MEU contended that the AEMC "cleverly" characterised the LTIC as being achieved by ensuring there is incentive for investors to invest in the networks, and disincentive when investment is not required. MEU considered that this emphasis on investment and investors took the focus away from the interests of the consumers who were required to pay for the network services and the impact that electricity prices had on their daily lives.

96 ECA devoted a significant portion of their submissions to the new limited merits review process, addressing what they considered to be intended from the introduction of the process. For example, ECA submitted that while SAPN does have a responsibility to meet its regulatory and other obligations, the question before the Tribunal is whether SAPN's Regulatory Proposal represents the most efficient way of meeting such responsibilities and obligations. In this respect, ECA referred to the aim of the energy market reforms, identified by the (former) Standing Council on Energy and Resources (now COAG Energy Council), to "restore the focus of the electricity market on serving the long term interests of consumers".

97 ECA also contrasted this case before the Tribunal with that of a NSW and ACT proceeding with respect to the absence of a consumer advocacy group as a party to the proceeding, noting that in *Applications by Public Interest Advocacy Centre Ltd and Ausgrid* [2016] ACompT 1 ('***Ausgrid***'), the Tribunal held at [64]:

> *Given the role of PIAC, and the relevance of its submissions to the Tribunal's functions and responsibilities under the legislation, the Tribunal has not needed in these matters to address separately the matters which emerged in the course of the consultation process. The role and submissions of PIAC have encompassed those matters.*

98 As such, ECA submitted that it was particularly important for the Tribunal to carefully consider and place weight on the submissions of SACOSS put forward in the consultation.

99 Relevantly, in its written submissions, SACOSS urged the Tribunal to continue to

> *consider its consultation obligations once the parties have had an opportunity to respond to matters raised at the public forum, and demonstrates in its reasons for*

> *decision on the review how the submissions made through the consultation process have been considered by the Tribunal.*

100 Before going to this issue, the Tribunal makes mention of the submissions of the Minister. It was the Minister's contention that the Tribunal should affirm the Final Decision. In the course of these reasons, the Tribunal traverses the issues raised by the Minister, although without specific attribution to the Minister as intervenor. These issues were effectively argued by both SAPN and the AER, and need no repetition. Nevertheless, one submission of the Minister does require specific mention relevant to the consultation process.

101 The Minister submitted that the efforts of the consumers who took the time to participate in the community consultation should be recognised and their submissions to the Tribunal must be considered as part of the review. The Tribunal accepts this submission, and acknowledges that the participants in the consultation took time out of their own businesses and life to be part of the review, representing various consumer interests.

102 In light of the ultimate decision of the Tribunal, it is unnecessary to otherwise comment on the Minister's helpful submissions.

103 It should also be observed, as the following reasons indicate, the decision of the Tribunal has been reached on the basis of the contentions made by SAPN and the AER, and not by direct reference to submissions made during the consultation process. This is not because such submissions are not relevant to the review, but because in this review the decision to affirm the Final Decision has been readily arrived at by focussing on the submission of the parties and in determining whether any error had occurred on the part of the AER. Nevertheless, the consultation process and the submissions of consumers (and the Minister) may have become particularly significant (if error had been found in the Final Decision) in the consideration of the materially preferable NEO decision. This has been unnecessary in this review as no error has been found to occur.

GROUNDS OF REVIEW

104 SAPN has identified multiple grounds of review in respect of each of the topics for review. In *Application by ATCO Gas Australia Pty Ltd* [2016] ACompT 10 ('***ATCO* 2016**'), the Tribunal outlined the nature and scope of each of the relevant grounds of review: error or errors of fact, incorrect exercise of discretion, and that the decision under review is unreasonable: see *ATCO* 2016 at [36]-[48]. The Tribunal considers these principles to be applicable in respect of the present application by SAPN.

105 The Tribunal now turns to consider in detail each ground of review by reference to the submissions of the parties. There was a substantial degree of repetition and overlap in the submissions dealing with each ground of review, and the Tribunal has attempted to address the significant and determinative issues to arrive at its decision.

Cost of corporate income tax (gamma)

106 Gamma is one of the required parameter inputs into the post -tax revenue model ('**PTRM**') used under the NER for the determination of allowable revenues for a DNSP. It represents the "value" of imputation (tax) credits arising from company tax payments which are distributed with dividends to shareholders. These can be expected to reduce the required return on equity of shareholders (relative to receiving returns without such tax credits attached).

107 However, in the PTRM, rather than applying an estimated value of gamma to adjust the required rate of return on equity, the estimate is instead applied to reducing the revenue required to compensate the company for corporate tax paid. Consequently the return on equity incorporated into the allowed rate of return is calculated ignoring the imputation credit component of returns to shareholders. This approach draws on a demonstration by Professor Bob Officer (The Cost of Capital of a Company under an Imputation Tax System, Accounting and Finance, May 1994) of the equivalence of several such alternative approaches to valuation of company cash flow streams.

108 Because gamma is unobservable, and also because of conflicting interpretations of the word "value" in its definition, there has been ongoing debate over the appropriate numerical value to use in the PTRM. In its Final Decision, the AER applied a value for gamma of 0.4, whereas the applicant SAPN argued for a value of 0.25. This difference has a significant negative impact on the allowable revenue for SAPN over the regulatory control period which it estimates to amount to $85.2 million. The AER argues that the effect would be less than this because of the need to adjust other parameters accordingly in the PTRM, as discussed later. SAPN argues that the AER made errors in determining to use a value of 0.4 for gamma, and contends that it should have accepted the proposed value of 0.25.

109 This same issue arose in the 2015 determinations by the AER for the NSW DNSPs, which was also appealed to the Tribunal by the affected parties (arguing for a gamma value of 0.25 rather than the AER's use of 0.4). That (differently constituted) Tribunal ruled on 26 February 2016 in the *Ausgrid* decision in favour of the applicants, and remitted the matter

back to the AER to recalculate allowable revenues using a gamma value of 0.25. The AER has, in turn, appealed that decision to the Full Court of the Federal Court. No determination has yet been made by the Full Court.

110 This Tribunal determined that despite the existence of that appeal, it was appropriate for it to hear this review rather than leave the matter to be determined conditional on the outcome of the hearing of the Full Court of the Federal Court. The Tribunal has a legislative responsibility to hear and determine the review (within a statutorily delineated period of time), and should proceed accordingly.

111 It was also contended by SAPN that this Tribunal should follow the *Ausgrid* decision, or alternatively, treat it as highly persuasive. Undoubtedly, each differently constituted Tribunal should consider the importance of consistency between Tribunal decisions, but this is not the sole determinative factor nor is consistency an unqualified value. Consistency may lead to arbitrariness of decision-making, and may not produce the correct legal and just result in the particular case before the Tribunal. Each Tribunal, considering the application before it, and dealing with the relevant parties, must in accordance with the law, the issues before it, and the evidence, consider and determine the matters raised before the Tribunal.

112 It is to be recalled the Tribunal is an administrative decision-maker, not a court of law. The Tribunal cannot conclusively decide questions of law. The general statements of principle the Tribunal articulates will not and cannot have the same force as the development of principles of general law determined by the courts. The function of the Tribunal is a reviewer of decisions, and is not a primary decision-maker. The Tribunal has a responsibility to determine individual cases based upon the evidence and arguments put before it. This Tribunal proceeds accordingly.

The role of gamma in the PTRM

113 The NER (r 6.3) specify that the DNSP's revenue requirement is to be calculated using the "building block" approach. Rule 6.4 provides detail on the building block components. Two components are relevant in this matter. One is the allowed rate of return on capital which is to be calculated in accordance with cl 6.5.2. The NER (cl 6.5.2(d)(2)) specifies that the allowed rate of return "must be … determined on a nominal vanilla basis that is consistent with the estimate of the value of imputation credits referred to in clause 6.5.3." The second component (cl 6.4.3(b)(4)) is that "the estimated cost of corporate income tax is determined in accordance with clause 6.5.3".

114 Clause 6.5.3 of the NER states that:

> *The estimated cost of corporate income tax of a Distribution Network Service Provider for each regulatory year (ETC_t) must be estimated in accordance with the following formula:*
>
> $ETC_t = (ETI_t \times r_t)\,(1 - \gamma)$
>
> *where:*
>
> *ETI_t is an estimate of the taxable income for that regulatory year that would be earned by a benchmark efficient entity as a result of the provision of standard control services if such an entity, rather than the Distribution Network Service Provider, operated the business of the Distribution Network Service Provider, such estimate being determined in accordance with the post-tax revenue model;*
>
> *r_t is the expected statutory income tax rate for that regulatory year as determined by the AER; and*
>
> *γ is the value of imputation credits.*

115 Thus, the value of imputation credits provided to shareholders is deducted from that part of the allowed cash flows required to meet tax obligations. Under the “vanilla” WACC approach, those tax obligations are calculated after allowing for the effect of the tax deductibility of interest on debt. Consistency of approach means that the allowed rate of return on the regulatory asset base (another component of allowed cash flows) is calculated as a “vanilla” WACC. This is a weighted average of a cost of debt (pre company tax – ie ignoring the tax deductibility of interest at the company level) and the cost of equity (ignoring returns to shareholders in the form of imputation credits). This “vanilla” WACC is also used to convert cash flows over, and the regulatory asset base at the end of, the regulatory control period to a present value to achieve a zero NPV condition for a smoothed set of revenues or prices over the regulatory control period.

116 This “vanilla” WACC approach, for use under an imputation tax system, has its genesis in the aforementioned paper by Professor Officer, in which he demonstrated the equivalence of a zero NPV condition for a set of future cash flows under alternative approaches. One was the “vanilla WACC” approach in which net cash flows to be valued have company tax payments (allowing for tax deductibility of interest) deducted. This involved company tax being defined as net of the value of imputation credits distributed to shareholders. For consistency, required rates of return (the discount rates) ignore personal tax consequences, including the effects of imputation. Among the alternative approaches was a dividend imputation version of the standard textbook approach. In that, cash flows are calculated, after company tax, “as if” the company were unlevered, such that there is no tax deduction for debt interest allowed.

Rather, the required return on debt is the after-company-tax cost of debt. Moreover, the company tax figure ignores imputation credit implications, and the required return on equity is lowered by some amount related to the value of imputation credits.

117 Two important considerations flow from this. One is whether the nature of the Officer approach has explicit implications for the interpretation of the term "value of imputation credits" used in the PTRM and the NER. The second is how a "value" of imputation credits should be estimated given the interpretation which is (or should be) adopted. These are the two issues at the heart of the dispute between SAPN (and other DNSPs) and the AER.

Regulatory background

118 The dispute over gamma needs to be placed in the context of changes made to the NER in November 2012 which changed the terminology used to describe gamma. Prior to that change, gamma was defined as "the assumed utilisation of franking credits". Subsequently it has been defined (NER cl 6.5.3) as "the value of imputation credits". No specific definition of what that term means, or how it is to be estimated, is given, other than that it needs to be consistent with the "vanilla WACC" approach.

119 Those rule changes also gave increased flexibility to the regulator in determination of the value to be chosen for gamma. "The current prescription of the gamma value of 0.5 in clause 6A.6.4 has also been removed to allow the regulator the ability to estimate an appropriate value that reflects the best available evidence at the time of a decision and would therefore result in a rate of return that meets the overall objective." (AEMC, Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, p 68).

120 Other than this statement, there appears to be no other explanation given for the change in terminology from "assumed utilisation" to "value", although the latter term (even though not specifically defined) is more consistent with the flexibility given to the regulator and requirement (NER cl 6.5.2(e)) that:

> *In determining the allowed rate of return, regard must be had to:*
>
> *(1) relevant estimation methods, financial models, market data and other evidence;*
>
> *(2) the desirability of using an approach that leads to the consistent application of any estimates of financial parameters that are relevant to the estimates of, and that are common to, the return on equity and the return on debt; and*

> *(3) any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt.*

The regulatory determination process.

121 In its initial proposal, SAPN proposed a value for gamma of 0.25, calculated as the product of a distribution rate of 0.7 and a "theta" value ("the value of distributed imputation credits to investors who receive them": SAPN, Regulatory Proposal, p 320) of 0.35. It noted that the latter figure (0.35) was different to that contained in the AER Rate of Return Guideline ('**ROR Guideline**') (where 0.7 is proposed) and also argued that the interpretation adopted by the AER of the "value of imputation credits" in those guidelines was incorrect.

122 It argued that the AER had inappropriately discarded a correct (in SAPN's view) prior approach which interpreted theta as the "value" of imputation credits, and which led to emphasis being given in its estimation to "market value studies" (such as dividend drop-off studies). Instead it had adopted an approach based on a "utilisation" rate. SAPN argued that rather than seeking to estimate the value of distributed imputation credits, the AER instead seeks to estimate what it refers to as "the before-personal-tax reduction in company tax per one dollar of imputation credits that the representative investor receives". Elsewhere in the Explanatory Statement, the AER refers to its conceptual definition of theta as "the expected ability of equity holders to use the imputation credits they receive to reduce their personal tax". (The references are to AER, Explanatory Statement: Rate of Return Guideline, December 2013, pp 165 and 174 respectively). By incorrectly (in SAPN's view) adopting this approach, the AER placed more weight on information from equity ownership and tax statistics than market value studies.

123 It is worth referring back to the Explanatory Statement of the ROR Guideline (pp 166-7) from which those statements have been extracted, since fuller reading of the document makes clear both the AER's approach and conceptualisation of theta, and also its perspective on earlier interpretations of gamma and theta by the Tribunal and others:

> *We consider the relationship between the representative investor in the market and the implied representative investor from estimation methods such as tax studies and dividend drop off studies). We consider this relationship is critical in assessing what we are estimating and which estimation methods are fit for purpose.*
>
> *To answer the question of the appropriate representative investor, we considered afresh:*
>
> > ** the Sharpe-Lintner CAPM framework under imputation as derived in Officer, Monkhouse, Lally and Van Zijl, and Lally*

> ** analysis of this conceptual framework by academic experts*
>
> ** the construction of the corporate tax building block in the rules and how this interacts with the Officer framework used within the rate of return.*
>
> *Our analysis of these issues is set out in section 9.3.1, and further in appendix H. Having undertaken this analysis, we conclude that we did not fully adopt or address important aspects of this analysis during the 2009 WACC review. As a result, the Tribunal review focused only on the particular suitability of tax value studies and dividend drop off studies. This was with an incomplete conceptual framework. The Tribunal acknowledged this incomplete framework at several points in its reasons.*
>
> *We conclude that the representative investor:*
>
> ** Is the weighted average of investors within the defined market, where the weightings reflect market participation (equity ownership value) and risk aversion.*
>
> ** In this context, the defined market is investors in Australian equity, either domestic or foreign.*
>
> ** Is the representative investor at any hypothetical point during a trading year – that is, it does not disproportionately reflect an investor or set of investors at a particular point in time. This is because investors may invest at any point during the year. If a benchmark parameter is set using data from a short period in systematically different trading circumstances to the rest of the year, it produces an estimate that is only relevant to those circumstances.*
>
> *Having reached this view, we consider it has important implications for the practical task of estimating the value of imputation credits. The most important implication of this relationship is that the source of evidence the Tribunal adopted for the utilisation rate (a dividend drop off study) does not produce an estimate for the representative investor. This is because dividend drop-off studies give the value weighted investor's valuation of imputation credits:*
>
> ** Based on the combined package of imputation credits, dividends, and other entitlements (unless adjusted for). That is, a value for imputation credits is not available via simple observation of the dividend drop off in these studies. The implied values for the franking credit and the cash component must be econometrically separated, which is difficult to do reliably. We discuss this further in appendix H.*
>
> ** For trades around the time of dividend distribution – that is, these studies only reflect trading around the cum-dividend and ex-dividend dates.*

124 In its preliminary decision, the AER rejected SAPN's proposal and determined that the value attributed to gamma should be 0.4, which was a departure from its ROR Guideline figure of 0.5. It explained that change as reflecting the available current information, and being based primarily on data from equity ownership and taxation statistics. These indicate (respectively) potential and actual utilisation of imputation credits. The AER argued that little weight should be given to market value studies due to a range of factors potentially affecting the robustness and interpretation of their results. The AER also departed from its ROR Guideline

in dropping from the list of alternative approaches the "conceptual guidelines" approach. The preliminary decision incorporated an extensive evaluation of alternative approaches to estimation of gamma and arguments provided by a range of experts and related evidence.

125 In its response to the preliminary decision and revised proposal, SAPN maintained its position that the value attributed to gamma should be 0.25, and provided additional expert reports in support of its position (and critical of the AER preliminary decision). It noted (SAPN, Revised Proposal, pp 370-1) that

> *There are two fundamental differences of view that explain how SA Power Networks' approach differs so substantially from that of the AER:*
>
> *1) the first fundamental difference of approach concerns what is meant by the term 'value of imputation credits' in rule 6.5.3. SA Power Networks and its advisors have consistently contended that this term must mean the valuation revealed in openly traded equity markets. The reasons for this view are explained at section (a) below. By contrast, in a range of regulatory documents published over the past five years the AER and its consultants have advanced one, two, three and even more formulations of argument and explanation that seek to bridge the gap between the reference in the Rules to a 'value', on the one hand, and the AER's preferred measure of the redemption rate …*
>
> *2) The second fundamental difference of approach concerns the set of comparator businesses that should be used when establishing a benchmark distribution rate. There are two key differences. First, the AER takes the view that the data for the distribution rate and the data for the valuation of imputation credits need to be drawn from the same set of firms. … Secondly, even if it were appropriate to look at a limited group of 'comparator firms' the AER's approach to selecting that subset is inconsistent over time and inconsistent with other aspects of its approach to rate of return regulation.*

126 These fundamental differences underpin the current dispute between SAPN and the AER (as well as being those considered by a previous Tribunal in the *Ausgrid* case).

127 In its Final Decision, the AER maintained its position on the appropriate value of gamma being 0.4. The AER (Final Decision, Attachment 4, pp 6-7) notes "[t]here is no consensus among experts on the appropriate value or estimation techniques to use. Further, with each estimation technique there are often a number of ways these may be applied resulting in different outcomes." The AER also noted the commonality of proposals from a wide range of service providers and that the value of gamma was one issue currently (at that time) subject to appeal by other service providers to the Tribunal. It concluded at p 18 that "[o]verall, the evidence suggests that a reasonable estimate of the value of imputation credits is within the range 0.3 to 0.5. From within this range, we choose a value of 0.4", and justified that choice

by the greater weight it placed on data from equity ownership and taxation statistics than on market value studies (such as dividend drop-off studies). The AER did not provide specific individual estimates for the two components of gamma (ie the distribution rate (F) and the value of imputation credits (theta)).

128 In reaching its decision, the AER adopted a clear position on the interpretation of the term "value of imputation credits". The AER based its decision on the view that "the value of imputation credits in NER cl 6.5.3 is the value of imputation credits to investors which, within the Officer framework, is the proportion of company tax returned to investors through the utilisation of imputation credits" (AER's Outline of Submissions, para 35).

129 In implementing that approach, the AER adopted a method for calculating gamma which involves multiplying the distribution rate (or payout ratio, "F") by the utilisation rate ("θ" or theta). There is disagreement over how best to calculate these two numbers, and whether "θ" should be interpreted as a utilisation rate or an implied market price of imputation credits. In its Outline of Submissions (at para 35), the AER:

> *(c) defined the distribution rate as the proportion of imputation credits generated by the benchmark efficient entity that is distributed to investors;*
>
> *(d) defined the utilisation rate as the value to investors in the market per dollar of imputation credits distributed, which reflects the extent to which investors can utilise the imputation credits they receive to reduce their tax or obtain a refund …*
>
> *(e) estimated the distribution rate using the "cumulative payout ratio approach", which uses data from the ATO on the accounts used by companies to track their stocks of imputation credits (franking account balances);*
>
> *(f) estimated the utilisation rate by giving varying degrees of weight to the different available estimation methods identified in the ROR Guidelines. …*

130 In estimating the utilisation rate the AER gave significant weight to equity ownership information, less weight to taxation statistics and lesser weight to market value studies (such as dividend drop-off studies).

Grounds of review

131 SAPN argues that the AER made multiple errors of fact, was unreasonable, or made an incorrect exercise of its discretion in determining that the appropriate value for gamma is 0.4. These commence at paragraph 37 of its Amended Application for leave, and run for several pages. Since they are, in many cases duplicative, interrelated, and overlapping, it is not

helpful for the Tribunal to reproduce them verbatim, but rather to summarize them in an order which facilitates a logical approach to analysis.

132 First, SAPN contends that the AER erred in misconstruing the correct interpretation of "value of imputation credits" through focusing on utilisation rather than implied market value.

133 Secondly, this misconstruction led the AER to incorrectly give greater weight to utilisation measures of imputation credit other than market based studies and particularly dividend drop-off studies.

134 Thirdly, SAPN contends that the AER erred in not recognising that investors would incur personal costs in extracting value from receipt of imputation credits which would reduce the value ascribed to them.

135 Fourthly, in calculating the value of imputation credits from equity ownership and taxation information, the AER used inappropriate data.

136 Fifthly, the AER in interpreting equity ownership and taxation figures failed to recognise that these are maximum possible values.

137 Sixthly, the AER did not accord sufficient weight to the dividend drop-off study of SFG Consulting ('**SFG**') due to misconceptions about the merits and reliability of drop-off studies.

138 The Tribunal notes that in relation to the concept of the "value of imputation credits" referred to in the first of the issues listed above, different theoretical models, all of which are simplifications of reality, with different strengths and weaknesses, and with different degrees of support among experts, may suggest differing approaches. Judgement about the weight to be given to alternative approaches would then be required, with resulting consequences for judgements about the subsequent issues.

Consistency of approach with the PTRM framework

139 In this section, the Tribunal addresses the first of SAPN's challenges – that the AER erred in misconstruing the correct interpretation of "value of imputation credits" through focusing on utilisation rather than implied market value.

140 Fundamental to the dispute over gamma is the correct interpretation of the word "value" in the NER which relates to one of the two components of gamma. It is accepted by all parties, and defined in the NER (cl 6.5.3) that gamma is the product of two components. Gamma is

the value of franking credits generated by the company tax paid by the entity. In turn gamma is defined as the product of the "F" (the distribution rate) and "θ" (theta – variously described as the utilisation rate or the market value (price) of distributed credits).

141 The AER places particular emphasis on the statement in cl 6.5.3 of the NER that the estimated cost of corporate income tax is to be "determined in accordance with the post-tax revenue model". That model (abbreviated as PTRM) is based on the derivation by Professor Officer of equivalence relationships between various formulations of the calculation of the NPV of future cash flows under an imputation tax system. In particular, Officer showed that the NPV=0 criterion could be described in a number of different ways, each involving different future cash flow concepts (with differences arising from different treatment of taxation) and correspondingly consistent interpretations of a discount rate (WACC). Officer's approach assumed a 100% distribution rate, which has been generalised in the common approach adopted by the AER and regulated entities of defining gamma as the product of "F" and "θ" as described above. Consequently, debate over the value of gamma involves debate over the values of both "F" and "θ", with the latter being the more contentious and fundamental to the interpretation of the PTRM model. Dispute over the value of "F" relates more to the choice of empirical data for its estimation rather than fundamental theoretical issues.

142 Officer observed (at page 4 of the aforementioned article) that:

> *A proportion (γ) of the tax collected from the company will be rebated against personal tax and, therefore, is not really company tax but rather is a collection of personal tax at the company level. Therefore, if we wish to define the effective company tax collection, we need to reduce T by the proportion γ. …*
>
> *Thus γ is the proportion of tax collected from the company which gives rise to the tax credit associated with a franked dividend. This franking credit can be utilized as tax credit against the personal tax liabilities of the shareholder. γ can be interpreted as the value of a dollar of tax credit to the shareholder.*

143 Officer also observed (p 4, fn 5) that:

> *Where there is a market for tax credits one could use the market price to estimate the value of γ for the marginal shareholder. i.e. the shareholder who implicitly sets the price of the shares and the price of γ and the company's cost of capital at the margin, but where there is only a covert market, estimates can only be made through dividend drop-off rates.*

144 There are (at least) two possible interpretations of these comments, as has been pointed out in submissions and expert evidence. First, the derivation by Officer places emphasis on gamma as the amount of tax credits which are utilised to reduce personal tax liabilities, and this is the

interpretation used by the AER. It also leads to an interpretation of "effective" company tax payments as being T(1 – γ) where T is the amount of tax collected at the company level. Secondly, Officer asserts that the market value of gamma will be set by the marginal investor, and that this can only be indirectly estimated by dividend drop-off rates. This, or at least the emphasis on drop-off studies, is the interpretation focused upon by SAPN and other DNSPs.

145 The Tribunal notes that the AER, in its reasoning in the ROR Guideline quoted earlier, did not interpret the drop-off evidence as relating to a marginal investor, but rather to some average investor prevailing at that specific time. The Tribunal also notes that Officer's interpretation of the role of a "marginal investor" in price determination is one commonly found in academic literature, as also is the notion of an average investor.

146 It is also worth noting the emphasis given by Officer to the "marginal shareholder" in the determination of share prices and the implicit price of γ. This underscores, and potentially calls into question, a commonly-heard assertion which is also made by SAPN. The marginal investor is not the same as the average investor. The proportion of tax credits used in aggregate (ie the average utilisation) provides no information about the value of tax credits to the marginal investor. Hence, contrary to the arguments advanced, the usage of tax credits is not an upper bound on the market value of tax credits – if that is set by some "marginal investor". Alternatively, if the market value is set by some "average" investor, an estimate for the average investor of the tax payment consequences of imputation credits distributed has relevance. As argued by SAPN, the value estimated in this way may be an upper bound due to a number of value-reducing factors. This is considered later.

147 This raises a fundamental consideration in the approach to the determination of a market value for imputation credits and implications for the cost of capital. Officer's approach, and consequent adoption of the "vanilla WACC" approach in the PTRM does not imply anything about the precise value of γ nor how it is determined. Officer does argue that the required return on equity will be lower than would otherwise be the case (in the absence of imputation) by the value of franking credits (γ) received with dividends. And while he uses an "imputation adjusted CAPM" to illustrate, the determination of the value of γ involved in that is not specified.

148 As noted above, there are, at least, two alternative theoretical approaches to considering the determination of γ. One relies on an average investor perspective, the other on a marginal investor. On this matter, the AER (Final Decision, Attachment 4, p 60) quotes from a recent

academic paper (A. Ainsworth, G. Partington and G. Warren, Do Franking Credits Matter? Exploring the Financial Implications of Dividend Imputation, May 2015):

> *Indeed, whether prices are set by a marginal investor, or by aggregation across investors, is an open question …*

149 The average investor perspective is reflected in versions of the CAPM which allow for the imputation system such as those developed by P. Monkhouse and by Professors M. Lally and T. van Zijl, and considered by the AER. These models give rise to a utilisation rate which "in equilibrium is equal to the weighted average, by wealth and risk aversion, of the individual utilisation rates of investors in the market" (Final Decision Attachment 4, p 52). In those models, this utilisation rate is also the value of distributed imputation credits in the sense that the equilibrium required rate of return on equity (ignoring the franking credit component received) is reduced by that figure. For example, if an investor required a 10% return on a stock offering returns in a form involving no receipt of imputation credits, then if an otherwise equivalent stock provided an imputation credit yield of 3% which was valued at 50% of face value, the required return ignoring imputation credits would be 8.5%. This would imply that in the PTRM where a vanilla WACC is used and the effect of imputation incorporated into the required tax revenue component of cash flows, the utilisation rate is an appropriate estimate of theta (as an input into gamma) which can be used.

150 SAPN challenges the validity of use of these tax adjusted CAPM models, and the implication that the utilisation rate (estimated using either shareholder nationality or taxation statistics) can be used to estimate gamma. The principal critique is one of the logical consistency of using a "domestic" CAPM model when an international perspective is required. Interpreting utilisation as reflecting the proportion of domestic investors, for whom imputation credits are valuable, implies that the remaining investors are foreigners. But, in that case, it is argued, the CAPM market portfolio should be the world portfolio, and those foreigner investors would have a wealth many multiples of the amount they have invested in the local market (and of domestic investors). In the limit, the role of domestic investors in domestic stock valuation and implied value of imputation credits would be zero. The AER (Final Report, Attachment 4 p 64) considers this critique and on the advice of its expert (Associate Professor J. Handley) rejects it. Underpinning that rejection is the argument that the CAPM assumes only that there is specified group of investors who hold the specified set (market) of assets being considered. The equilibrium individual asset prices and expected returns are derived by reference to their systematic risk relative to that specified market. In that framework,

which takes as given the wealth invested by foreigners in the domestic market, the weights implied in the determination of gamma would reflect relative wealth shares of the domestic market, not total wealth.

151 Such a framework may, or may not be reasonable, but there is no one generally accepted model for dealing with asset pricing in a domestic market where foreigners subject to different tax considerations participate. As the AER notes (p 64), an "international" CAPM (of which there are a number of variants) could be adopted but, as well as not being advocated by SAPN, this would require fundamental re-estimation of betas and cost of equity, as well as valuation of imputation credits.

152 On this matter, the Tribunal recognises the fact that models are, at best, simplifications of and approximations to reality. There has been, and likely always will be, debate over how to assess the relative merits of alternative models. One perspective is that models should be evaluated by explanatory performance, rather than by the reality of their assumptions. On this criterion, the possible lack of realism of the Monkhouse and Lally and van Zijl models, argued by SFG (Estimating Gamma for Regulatory Purposes, February 2015) for SAPN, is not necessarily a reason for rejecting them, provided that their predictions are not rejected empirically. Unfortunately, in terms of resolving the debate over these matters, the relevant empirical evidence is quite disparate.

153 An alternative approach to considering the valuation of imputation credits is based on assuming that it is the "marginal investor" who determines security prices and thus sets the value of imputation credits impounded into that price. As in standard price theory, investors may have different valuations for a stock (reflecting different information or personal considerations including tax), and specific amounts they demand at various market prices. Limits to arbitrage, risk, wealth constraints, or other factors may lead to their demands not being infinitely elastic at some price. Aggregated, these investor demands generate a downward sloping total demand curve for the stock. The market clearing price will be that at which the marginal investor's valuation equals that price, with some infra-marginal investors placing a valuation on their holding above that price. In theory, at least, the marginal investor is either a domestic investor for whom theta = 1 or a foreign investor for whom theta = 0. In practice, determination of share prices (from which implied market value estimates of imputation credit value might be derived) is more complex, reflecting market and individual characteristics (including limits to arbitrage).

154 There is no guarantee (nor reason to necessarily expect) that the marginal, price-setting investor will be the same type of investor at all points in time. For example, institutional features of the stock market mean that returns only have an explicit dividend (and franking credit) component (rather than comprising only capital gains or losses) if stocks are held on the date of record. Moreover, the franking component of dividends can only be useable if holdings satisfy the 45-day holding requirement around the ex-div date. There are also constraints on franking credit usage if the stock holding is hedged against price risk (such as by use of derivatives).

155 The marginal investor perspective has several implications for assessing dividend drop-off studies, which are based on prices being determined by arbitrage by marginal investors (or by average investors active in the market at that time). First, if drop-off studies are estimating valuation of a marginal investor, the imputation credit usage figure, being an average, is not a relevant upper bound for that valuation. It may be so, although not necessarily, for the alternative approach where valuation is based on the average investor. Secondly, for reliable information to be extracted from drop-off studies, constancy of the marginal investor pre and post the dividend ex-date is required. Otherwise the drop-off figures may reflect nothing more than a short-term change in the composition of investors, and not information about the role of imputation credits in determining the required return of longer-term investors.

156 In conclusion, the Tribunal is of the view, reflected in the diversity of expert opinion, that there is no generally accepted theoretical model for explaining the valuation of imputation credits. There is broad agreement across experts that the existence of the imputation system lowers, to some degree, the cost of equity capital to Australian, domestically operating, companies, relative to a classical tax system. That is, required returns ignoring imputation credits (ie expected cash dividends plus capital gains) will be lower if imputation credits are expected to be attached to cash dividends.

157 Within the framework of the PTRM and "vanilla WACC" requirement of the NER, this translates into a reduction in the revenue allowance for corporate tax payments. Within the Officer framework underpinning that approach, that revenue reduction could be interpreted as reflecting that some part of company tax payments is a pre-payment (withholding) of personal taxes. Alternatively, the interpretation could be that the revenue reduction is the value accorded by the market to that pre-payment of personal taxes and reflected in the (non-vanilla) cost of equity capital. Under the "average investor" approach these should, in theory,

coincide. Under the marginal investor approach, the relationship is indeterminate – unless specific assumptions about the identity (and constancy) of the marginal investor are made.

158 Unfortunately, the available empirical evidence is inadequate to enable confident discrimination between these alternative perspectives. There are a range of studies, reviewed in the AER's Final Decision, using market prices which attempt to estimate the extent to which imputation credits are capitalised into stock prices and thus their market valuation. There are a range of results, and experts are divided on the merits of the various approaches and techniques.

159 Consequently, the Tribunal is of the view that the AER did not err, nor was unreasonable, in giving most weight to the "utilisation" approach. It considered the range of alternative approaches, recognised the diversity of views of experts on their merits (both theoretical and empirical), and made a judgement call. In doing so, it demonstrated responsiveness to the empirical evidence in lowering its estimate of gamma from 0.5 as proposed in its ROR Guidelines to a value of 0.4. The Tribunal recognises that this decision is the converse of that made by a differently constituted Tribunal in the *Ausgrid* case. The reason for this difference is twofold. First, submissions in this hearing gave greater attention to the theoretical underpinnings of the PTRM and "vanilla WACC" framework. Secondly, and as discussed immediately below, this Tribunal is of the view that the dividend drop-off evidence should be viewed in the context of the theoretical model underpinning it, and that there are significant uncertainties associated with extracting reliable evidence about tax-related parameters (such as gamma) from such studies.

Dividend drop-off evidence

160 The Tribunal now considers the second and sixth issues noted above which both assert that the AER should have given more (or complete) weight to evidence from dividend drop-off studies (and in particular the SFG study).

161 SAPN (and other DNSPs in other cases) argue that, in estimating the value of distributed imputation credits, most if not complete weight should be given to results from dividend drop-off studies. In particular, it is argued that the primary piece of evidence should be the results from a 2013 study by SFG commissioned by the Energy Networks Association. The latest version of this study updates an earlier 2011 study by SFG which had been undertaken in response to directions from the Tribunal. In contrast the AER argues that evidence from this type of approach should be given least weight.

162 The 2011 study concluded that "the appropriate estimate of theta from the dividend drop-off analysis that we have performed is 0.35 and that this estimate is paired with an estimate of the value of cash dividends in the range of 0.85 to 0.90." The 2013 study which uses data from 2001 to October 2012 generates similar results.

163 The Tribunal notes that the SFG study is very clear about the data used and econometric techniques employed. Different specifications (reflecting statistical considerations required to achieve unbiased, efficient estimates) of the basic relationship estimated generate similar results. That basic relationship links the fall in stock price on the ex-dividend date (the drop-off) to the amount of the cash dividend and the amount of the franking (imputation) credit. Because the study includes dividend events which may involve no, partial, or full franking, it is able to estimate the sensitivity of the drop-off to both the size of dividend and the size of the franking credit in a regression relationship.

164 However, the Tribunal also notes that interpreting the drop-off sensitivity as evidence about the implicit value of a tax parameter such as the "value" of a franking credit (gamma) requires a number of further, quite strong, assumptions. In its Final Decision (Attachment 4, Section A.14) the AER gave explicit attention to issues involved in estimation of gamma from dividend drop-off studies. It considered the view of a number of experts including SFG (Professor S. Gray), Associate Professor J. Handley, Associate Professor M. Lally, Professor M. McKenzie and Associate Professor G. Partington, and examined a range of academic studies.

165 A number of issues regarding reliability of dividend drop-off studies were considered by the AER, but only one is substantive in this context, given the Tribunal's view that the methodology and approach of the SFG study is generally acceptable (or "state of the art" as claimed by the DNSPs). The Tribunal recognises that some researchers may prefer use of alternative approaches or choices of specific data in analysing drop-off rates, but offers no comment on those empirical matters. That is the question of whether the sensitivities of the drop-off rate to dividend characteristics as estimated in such a study can be reliably interpreted as reflecting specific tax-related factors (such as the value of gamma). On this there is marked disagreement between the experts, with SFG (Professor S. Gray) asserting that the value of imputation credits can be reliably inferred, and the others referred to above, advancing a range of reasons in support of an opposing position.

166 In its Final Decision (Attachment 4, p 48) the AER notes that:

- *There is no market for imputation credits and therefore there is no directly observable market price. …*
- *The value of imputation credits as estimated through a dividend drop off study:*
    - *is not necessarily a correct post company tax value before personal taxes and personal transaction costs (particularly demonstrated where the study estimates a value for cash dividends materially below their face value as the SFG study does) …*

167 In coming to this conclusion, the AER liberally quotes criticisms of dividend drop-off studies from experts Associate Professor J. Handley, Associate Professor M. Lally, Professor M. McKenzie and Associate Professor G. Partington, and other authors. There are a range of criticisms, with the most significant being that of whether dividend drop-off information can provide information about tax parameters, such as the value of imputation credits. In this regard the AER quotes from a paper by K. Siau, S. Sault and G. Warren (2013) which references a range of other well-known published studies which have identified the problem that drop-off rates can reflect a range of other influences other than taxation:

> *A key methodological issue is that price movements around ex-dividend events encapsulate not only the tax differential effect, but may also reflect the presence of traders seeking to arbitrage dividends and noise associated with trading activity around ex-dividend dates. Drop-off ratios can be distorted by the need to compensate traders for transaction costs (Eades, Hess, and Kim ,1984); Lakonishok and Vermaelen, 1986; Karpoff and Walkling, 1988, 1990; Bali and Francis, 2011); or the risk involved (Fedenia and Grammatikos, 1993; Grammatikos, 1989; Heath and Jarrow, 1988; Michaely and Vila, 1995). Transaction costs may be substantial, and can drive the drop-off ratio below one (Kalay 1982, 1984; Boyd and Jagannathan, 1994). Market microstructure effects may also complicate estimation of market value, as discrete tick sizes can bias drop-off ratios downwards (Dubofsky, 1992; Bali and Hite, 1998).*
>
> *A further key methodological issue is the difficulty in attributing the observed drop-off value between cash dividends and imputation credits.*

168 The Tribunal also notes that the typical argument used to motivate use of drop-off studies is one of arbitrage based on differences between the cum-div price (and entitlement to dividend) and the ex-div price (with no entitlement to dividend). The “marginal investor(s)” would, in the absence of substantive transactions costs and risk, adopt a trading strategy to capitalise upon tax consequences. This behaviour would cause the price drop-off to reflect characteristics of the tax code, such as differences in capital gains tax rates and dividend tax rates, possibly allowing inferences to be made about the tax arrangements facing the marginal investor(s). But as noted above, evidence of the price drop-off differing systematically from the dividend amount could reflect a number of other factors in addition to, or other than, tax

implications. These also include the "marginal investor(s)" (with differing tax considerations) being different on the cum-div and ex-div dates, or different to the marginal investor throughout the rest of the year.

169 The Tribunal also notes that such a rationale for drop-off studies appears to make attempting to estimate the market value of franking credits from such a study highly problematic. The reason is that the operation of the 45-day rule impacts upon the consequences of such trading strategies. For example, purchase of a stock cum-div and sale on the ex-div day (as implied by an arbitrage argument where the marginal investor anticipates a sufficiently low drop-off) would generally void the ability of the investor to use franking credits attached to the dividend due to the 45-day rule. This type of arbitrage strategy would thus tend to imply an equilibrium expected price drop-off (where no arbitrage gains result) equal to the cash value of the dividend, regardless of how much imputation credits were valued by longer-term investors. The situation is obviously more complex than this since equilibrium requires analysis of capital gain/loss tax consequences from trading strategies involving sales by existing holders or short sales and associated stock borrowing costs – including requirements to compensate stock lenders for the equivalent of any franked dividends received.

170 The Tribunal is thus of the view that while dividend drop-off studies may convey some information about tax parameters and valuation of their consequences for the set(s) of investors determining stock prices around the ex-div date, there are too many other confounding factors to place sole, or even, major weight on such studies for the estimation of the value of franking credits in the context of the PTRM.

171 The AER makes a number of other criticisms of drop-off studies. A general one is that there have been a range of results, sometimes implausible, from different drop-off studies. The Tribunal accepts those observations as a matter of fact, but does not regard them as a valid reason to reject the statistical results of a particular study (such as that by SFG). However, as mentioned above, the fundamental issue is whether valid tax related valuation parameters can be reliably inferred from such statistical results. Because of the weight of expert evidence questioning that such inferences can be reliably drawn, and the AER reliance on that evidence in forming a judgement, the Tribunal does not believe it needs to address those other criticisms. The uncertainty associated with drawing conclusions about the value of imputation credits from any existing drop-off study (no matter how well specified and conducted) was sufficient for the AER to make a judgement to accord limited weight to this

type of evidence. Consequently, the Tribunal does not agree that the AER erred or was unreasonable in placing less weight on dividend drop-off studies in the estimation of the value of gamma.

The role of personal costs

172 In this section the Tribunal considers SAPN's third and fifth contentions. SAPN argues that (a) there are a range of personal costs faced by investors in obtaining "value" from imputation credits which would reduce the value below that implied by their face value, and (b) this would reduce the market valuation of imputation credits relative to estimates based on the shareholder nationality or taxation statistics. Thus, the required return on equity would be higher (gamma would be lower) than implied by using a gamma value based on the shareholder nationality or taxation statistics estimates.

173 Three types of such costs are emphasised. One is a time-value of money effect. It is argued that the delays investors experience in receiving tax offsets or rebates from using franking credits reduces their value relative to face value. A second one is the consequences of the 45-day rule, precluding investors from using tax credits unless they have held the stock unhedged for that length of time around the ex-div date. Some Australian investors may have violated this rule and thus the value obtained, in terms of tax reduction or rebate, from receipt of franking credits may be less than the face value received. The third argument is that investors who aim to maximise imputation credit receipts will suffer from reduced portfolio diversification which imposes a cost, in the form of increased risk, upon them.

174 There can be little doubt that the investor-level (or personal) costs involved in making and managing investments will affect the price they are willing to pay for (or sell) an asset. For some investors, certain of those costs might be high and for others inconsequential. How they impact upon market prices, and the valuation of certain asset characteristics such as imputation credit yield, is not something well determined by theory. In practice, market prices might incorporate the personal costs of a marginal investor for whom those costs are trivial (or otherwise), or reflect some average of such costs across investors. Moreover, the effects of such costs on asset demand will be intermingled with a range of other asset price determinants such as differential views on fundamental values and liquidity needs. There would thus, it seems, need to be a very strong case to identify some such general investor costs and attribute to them some systematic effect on asset prices (and valuation of imputation credits). This is particularly so when the argument advanced is that these factors

imply that predictions drawn from a theoretical model (in this case a tax-adjusted CAPM implying a price-setting role for some “average investor”) which ignores such factors, will be biased in a particular direction. Such factors could, for example, already be reflected in the composition of investors such that this group comprises those to whom such costs are of minor significance. It is not clear to the Tribunal that such a case has been substantiated.

175 SAPN contends that the delay in accessing tax benefits from receipt of imputation credits will reduce their present value to below face value. That may be the case for some investors, but would appear to imply logically that such investors will also discount the tax costs associated with any taxes yet to be paid on dividends. The net effect is unclear, and introduces the confounding effect of investor discounting of future tax liabilities from actual (or as yet unrealised) capital gains or losses which are otherwise ignored. More generally, it is not obvious that a fund manager who uses imputation credits to offset other future known or expected tax liabilities on their portfolio would find merit in applying such discounting. As a practical matter, the relatively short time lags and currently low discount rate which would likely be applied suggest that this effect is likely to be small. Because there may well be investors important to price determination who do not discount such tax-benefit delay consequences, the Tribunal is not convinced of the materiality of this argument.

176 SAPN contends that the 45-day rule will reduce the ability of domestic investors to utilise all imputation credits received. Evidence presented to the Tribunal about the reliability of tax statistics suggested that the materiality of this point is hard to judge. More generally, while this effect may be relevant, its effect on the valuation of imputation credits is far from clear. It is, for example, an institutional factor which is outside the formal structure of models used for analysis, such that the consequences with regard to results of such models which ignore it in their determination of asset prices is unclear. As noted earlier, the Tribunal also questions whether the existence of the 45-day rule (which voids imputation credits from short-term trading around the ex-div date) impedes the ability of dividend drop-off studies to inform on the value of imputation credits.

177 SAPN contends that domestic investors who structure their portfolios to acquire imputation credits will incur costs due to loss of diversification benefits, and that this will reduce the implicit price they are willing to pay for imputation credits to something below face value. Given that there is a well-documented “home-bias” in investor portfolios (found

internationally generally regardless of tax systems), implying incomplete diversification benefits, the extent to which this is an additional factor of significant materiality is unclear.

178 The Tribunal is of the view that while some investors do experience investor level (personal) costs in dealing in equities, these can vary substantially across investor groups. It is thus not clear what effect such costs will have on equity market prices or on the need to adjust estimates for implied values of franking credits drawn from shareholder distribution or tax statistics.

Estimates using shareholder nationality, company type, and tax statistics

179 SAPN's contention that the AER erred in adopting a wrong conception of "value" of imputation credits and consequently placing more weight on shareholder and tax statistics then on dividend drop-off results for estimation purposes has been dealt with earlier. The Tribunal determined that there was no error involved.

180 This leaves as a matter for further contention the appropriate statistics to be used which forms the basis of the fourth contention of SAPN. SAPN contend that the AER erred in three ways in data choices in estimating gamma. However, because the AER only gave a range of figures for each of the inputs to the gamma calculation and not explicit figures used in reaching its final estimate of gamma, the issue before the Tribunal is whether the net result of its decision based on these ranges for inputs is unreasonable or in error. To assess that, however, it is necessary to determine whether the ranges adopted were reasonable.

181 The following Table (extracted from Table 1 of SAPN's Outline of Submissions) provides a concise summary of the AER analysis and decisions which are points of contention.

Input	**ROR Guideline**	**Final decisions**	**Reason for change**
Distribution rate	0.7	0.7 for all equity 0.77 for listed equity	AER takes into account the distribution rate for all equity and listed equity in the Final Decision.
Theta estimate from equity ownership	0.7-0.8	0.56-0.68 for	Further analysis by the AER demonstrated that its previous

data		all equity 0.38-0.55 for listed equity	estimate of 0.7-0.8 was too high.
Theta estimate from tax statistics	0.4-0.8	0.45	Further analysis by the AER demonstrated that the best estimate is 0.45.

The distribution rate

182 First, the AER considered the possibility of a different value for the Distribution Rate (F) to the figure of 0.7 based on all equity, which was adopted in the ROR Guideline. An alternative figure of 0.77 was considered based on listed equity only. This raises the question of whether the distribution rate of the hypothetical benchmark efficient entity (‘**BEE**’) is better proxied by the average of any company or listed companies only. SAPN asserts that by having regard to the distribution rate of listed companies the AER was in error. The principal reason advanced is that the BEE is assumed to have only domestic earnings, whereas many large listed companies have foreign earnings which do not generate imputation credits. Then, if the dividend payout ratio (dividends/earnings) is the same as for the BEE, the distribution rate of imputation credits (credits distributed/credits generated) will be higher. That argument, does not, however, allow for the possibility that such companies with foreign earnings have a lower dividend payout ratio.

183 More generally, dividend payout ratios and distribution rates can be expected to vary between companies based on ownership characteristics and need/preferences for internally generated capital. Unlisted companies vary markedly. At one extreme there are small companies owned by individuals on high marginal tax rates who may prefer earnings retention to generate concessionally-taxed long-term capital gains or to defer the additional tax which would need to be paid on franked dividends. At the other extreme, large foreign-owned Australian registered companies may also prefer retention and reinvestment of earnings rather than distribution of dividends and attached franking credits which would be wasted.

184 The conclusion the Tribunal reaches is that there is no compelling reason which has been advanced to believe that the “average” unlisted company is any better or worse than the “average” listed company as a proxy for the BEE. Consequently the Tribunal does not

believe that the AER made an error or was unreasonable or incorrectly exercised its discretion in considering estimates of distribution rates for listed entities.

Equity ownership data

185 The AER placed most reliance on estimates of the domestic ownership rate for estimating theta. This is consistent with its conceptual interpretation of the role of gamma in the PTRM and the NER as considered earlier in these reasons, and with which this Tribunal does not find error.

186 SAPN contends that the AER then erred in two regards in use of ownership statistics. First, it argues that the AER did not take account of the fact that the domestic ownership percentage is at best an upper bound on the value of theta because of the inability of some investors to use imputation credits. As this Tribunal has noted previously, that argument is incorrect if it is believed that stock prices (and thus imputation credit value) are determined by some marginal investor. Even if the average investor perspective is taken, there may be other relevant factors, not adequately captured in theoretical models, which preclude an interpretation as an upper bound.

187 Secondly, SAPN contends that the actual equity ownership figures used by the AER are essentially not fit for purpose. The principal argument advanced here is that the AER uses data since 2000 in determining the potential range of relevant values for equity ownership. Instead, SAPN argues, it should be the current rate of domestic equity ownership which should be used. It points to the AER's own analysis (Final Decision, Attachment 4, p 96, Figure 4-3) showing that the domestic ownership share at the end of 2014 was 0.6 for total equity and 0.45 for listed equity. These were both marginally below the midpoint of the ranges of 0.56-0.68 and 0.38-0.55 respectively in post-2000 data considered by the AER.

188 The AER's counterargument is that (a) there is considerable temporal variability in ownership shares; (b) there is a degree of uncertainty about the precision of available information; and (c) the regulatory control period spans five years such that it is necessary to predict ownership rates over the whole of that period (AER's Outline of Submissions, para 96). The Tribunal is unable to see the validity of the last point in the context of estimating the value of imputation credits as at the start of the regulatory period. It relates to an interpretation of theta as purely a utilisation rate over a five-year period. While the Tribunal recognises the need for analysis of historical data to reduce uncertainty surrounding current figures, it would expect that sound reasons would be provided for using figures significantly

different from the current value given that this is close to the historical average. As discussed below, the implied value for theta used by the AER in adjusting the MRP is 0.6 which is not inconsistent with the 2014 domestic ownership share of total equity.

189 SAPN also asserts (Outline of Submissions, para 127) that the listed company, domestic equity ownership, figure will provide a better proxy (than the total figure which includes unlisted companies) for that applicable to a BEE. This argument appears at variance with SAPN's argument in the context of distribution rates (discussed above) that unlisted equity would provide a better proxy than listed equity for the BEE. The Tribunal is however willing to accept that there might be different proxies better suited to estimation of different characteristics of the hypothetical BEE. Nevertheless, the Tribunal has not been presented with convincing evidence that the listed equity data should not have been considered by the AER.

190 The Tribunal thus does not find that the AER erred or that its decision was unreasonable in considering historical data on domestic equity ownership shares for both listed and all companies. The issue of whether it was unreasonable in forming a judgement about gamma, based on weighing a range of evidence, including the implied choice of values from the ranges examined, is considered below.

The use of taxation statistics

191 SAPN contends that the AER erred, or made an incorrect exercise of discretion and was unreasonable in its use of taxation statistics by failing to recognise that the credit redemption rate of 0.45 from such statistics (which number is not in dispute) (a) did not indicate the value of imputation credits to investors and (b) and was an upper bound on the value of theta.

192 The AER gave less weight to the taxation statistics than to equity ownership information (and more weight than to market value (dividend drop-off studies). It argued for giving greater weight to equity ownership data on the grounds of concerns about the reliability of the tax statistics.

193 The Tribunal was presented with a range of information which indicates that there is a considerable degree of uncertainty about the reliability of the tax statistics regarding the redemption rate of imputation credits. That, of itself, implies that the redemption rate figure from tax statistics is not an upper bound for the utilisation rate, but rather a noisy estimate. Whether, ignoring that fact, it would be an upper bound for the market valuation of

distributed credits has been considered earlier. As explained there, the answer to that question depends upon the unsettled issue, on which experts disagree, of how stock market prices are determined. In particular, if a marginal price-setting investor perspective is taken, the average utilisation rate implies nothing about valuation by a marginal investor. If an average investor perspective is taken, then the figure is potentially more relevant to being a noisy upper bound on valuation.

194 The Tribunal does note, however, that the arguments advance in the context of the shareholder-nationality approach for a market value less than implied by those statistics do not all apply in this case. In particular, the argument relating to the 45-day rule would be irrelevant, since any effect of that would already be reflected in the utilisation rate being less than 100%.

195 The argument that the redemption rate does not reflect the value of imputation credits to investors has also been considered earlier. The Tribunal has noted that experts are divided on this issue, and has found no reason to accept that the interpretation by the AER is incorrect.

Conclusion

196 In the face of significant uncertainty, the approach by the AER of considering a range of approaches to estimating gamma and applying different weights to those approaches is, the Tribunal believes, appropriate. It is clear that some experts would apply different weights to the alternative types of evidence, and that some support the AER's relative ranking while others disagree. In particular, some would accord much higher weight to results of dividend drop-off studies. The Tribunal has noted the arguments about the problems of deriving reliable tax-related parameters such as investor valuation of imputation credits from drop-off parameters, and is of the view that the AER did not err in forming the judgement it did regarding weight to give to different forms of evidence.

197 The Tribunal also feels it worth commenting on the interrelation between the value of gamma and the market risk premium ('**MRP**') estimate, since this was raised in submissions. Specifically, the AER noted that in deriving a value for the MRP based on historical data from both pre and post imputation periods, an adjustment incorporating gamma is required. It appears, from evidence submitted, that in doing so the AER has implicitly adopted a higher gamma for that adjustment than used explicitly in the matters considered here. Doing so means that the MRP and allowed rate of return on equity is higher than would be the case if a lower value was used. The AER states (Final Decision, Attachment 3, p 398) that "[o]ur

adjustment is based on investors valuing distributed franking credits at 60 per cent of their face value".

198 At the risk of repetition of earlier remarks, but to elaborate, this arises because the PTRM is a post-company tax model in which company tax payments are measured net of the implied value of personal tax pre-payments resulting from distribution of imputation credits. The "vanilla WACC" rate of return on equity component is before investor tax consequences arising from, or costs incurred in, deriving that return. It is the rate of return the company would need to provide in the form of capital gains and cash dividends to meet shareholder requirements assuming that no imputation credits were distributed. Consequently, the allowed rate of return in the revenue determination is increased, relative to that (capital gains and cash dividends return) observed in the market, by the value of imputation credits distributed. In adjusting historical data on the MRP to reflect the introduction of imputation in 1987, the MRP data post that date is increased by an assumed value of imputation credits received by investors. This is offset (to some degree) by the subtraction of the value of distributed imputation credits from the allowed revenues for meeting tax obligations. Thus, a lower assumed valuation of gamma would have two partially offsetting effects on the allowed revenue. The rate of return on capital component would be reduced (since there would be a smaller upward adjustment of the rate of return) while the tax component would be increased (due to reduced deduction of a lower value of distributed credits).

199 In theory, if not in practice, there are circumstances where these effects could be exactly offsetting. One could be where the company was fully equity financed, had a CAPM beta of unity, distributed all cash flows, and the required return involved grossing up the observed market returns and MRP under imputation by a gamma factor which was used also in determining the tax revenues. In that case, it would appear that the actual value of gamma might be irrelevant to the allowed revenue determination – it would simply affect the allocation of revenue between the rate of return and tax components. In practice, the effects are less clear due to complications such as (a) estimation of a market rate of return using both historical pre-imputation and post-imputation observations; (b) tax code features such as differences in accounting and tax treatment of depreciation; (c) use of debt financing; and (d) equity betas different from unity.

200 In the current context, the possible use of a higher theta value in adjusting the historical MRP than in determining the tax revenue allowance (although the AER does not provide

information on the precise value used for this latter figure) could involve some inconsistency which would work in favour of SAPN. Alternatively, if a theta value of 0.6 was also applied in the determination of gamma, a result for gamma of 0.4 suggests use of a distribution rate of slightly below 0.7. That would make redundant the debate over whether AER's consideration of the distribution rate of 0.77 of listed companies is preferable to a consideration of all companies (with a distribution rate of 0.7).

201 The Tribunal simply notes that (a) consistency in the adjustment of the MRP for the value of franking credits distributed (theta) and in the value assumed for determining the net corporate tax revenue component is desirable; and (b) assumption of a higher or lower value for theta (and thus, ceteris paribus) gamma will have partially offsetting effects on the rate of return and taxation components of allowable cash flows.

202 The grounds of review regarding the value of gamma are rejected.

Return on debt

203 The issue regarding the return on debt is the choice of transition arrangements between the previously used approach for determining the cost of debt of a benchmark efficient DNSP and a new approach to be fully implemented by the end of a 10-year transition process. The previous approach is referred to as an "on-the-day" approach in which the cost of debt for each year of the regulatory period was determined as that prevailing at the start of the regulatory period. The new approach is referred to as an "historical trailing average" approach and was facilitated by a change to the NER described below. In that approach the cost of debt in each year of the regulatory period is calculated as the average cost of the debt portfolio of a benchmark efficient DNSP at the start of that year, resulting from assuming that it had raised equal amounts of 10-year maturity debt over the past 10 years. It can thus vary in each year of the regulatory control period.

204 There is no dispute on the decision to change to the new approach, nor on the benefits of some form of gradual transition to the new approach. The issue is purely about the specific transition arrangements to be used. Moreover, it relates to the transition of only one of the two components of the cost of debt, namely the debt risk premium ('**DRP**'). Both parties are in agreement on the merits of, and on the form of, a gradual transition arrangement for the risk-free component of the cost of debt.

205 This transition of the risk-free component involves a determination in the first year of the regulatory period using the previous “on-the-day” approach – which takes the rate prevailing in the market at (or just prior to) the start of the regulatory control period. In each subsequent year the weight given to the “on-the-day” figure (ie the rate at the start of the regulatory control period) in calculating the return on debt for that year would decline by 10% per year. The risk-free rate (calculated as an average over some previously agreed averaging period) just prior to the start of each subsequent year would be given a weight of 10% and would remain part of the calculation with that same weight for 10 years. Thus, the on-the-day rate would have 90% weight in the second year and the average rate determined for the start of that second year would have 10% weight. In the third year, the on-the-day weight would decline to 80% with the rate determined for the start of that third year being given a weight of 10% – and the rate determined for the start of the second year remaining in the calculation with a weight of 10%. After 10 years of this process full adjustment to the new “historical trailing average” approach will have occurred.

206 In the Final Decision the AER considered four options for transitioning to the new approach. The dispute relates to only two of those options. One of the options starts with an on-the-day rate for the first regulatory year of the regulatory control period and then transitions to the average approach over 10 years in the manner described above (‘**Option 2**’). Option 2 was the option adopted by the AER in the Final Decision and it is the same transition arrangement as outlined by the AER in its ROR Guideline – although there was no (nor needed to be no) separation of borrowing costs there into a risk-free and DRP component made there. The other option uses a hybrid approach. Under this approach the risk-free rate would transition like Option 2, however the DRP would transition immediately (‘**Option 3**’). Option 3 is the transition approach ultimately advanced by SAPN and rejected by the AER. SAPN challenges the decision of the AER that there should also be gradual transition arrangements for the DRP component.

207 SAPN argues that the correct approach, which it proposed, should instead be an immediate shift to Option 3.

208 The DRP prevailing at the commencement of the regulatory control period was lower (at 1.95% per annum) than its 10-year trailing average which SAPN argued was 2.37% per annum at that date, giving a gap of 0.42% per annum for the first year of the regulatory control period (SAPN’s Submissions in Reply, Figure 1). Because of the past history of the

DRP (with much higher values than 1.95 occurring in the wake of the global financial crisis), SAPN argue that the gap between the Option 2 and Option 3 allowed DRPs would be significantly higher in subsequent years of the regulatory control period. That is, the Option 3 DRP would be more than 42 basis points above the Option 2 DRP in later years of the regulatory control period.

209 It is possible to calculate the effect of the AER's decision, compared to SAPN's preferred approach, on the allowed revenue over the regulatory period. Future values of the DRP prevailing at the start of each year (and thus the allowable DRP) are, by definition, unknown at the start of the regulatory period. But the effect of a particular outcome on the allowed DRP is the same under both Options 2 and 3. The reason is that the DRP prevailing at the start of a future year enters into the calculation of the allowable DRP for that year (and each of the subsequent 10 years) with a weight of 0.1 in both cases. While the difference in the allowed DRP between the two options will change year-by-year due to the "rolling off" of the DRP from 10 years prior in Option 3, the newly included current year DRP will affect the average calculated by both options equivalently.

210 SAPN argues that in comparing Options 2 and 3 there is a material reduction in allowed revenue under the AER's choice of Option 2, which would be in excess of $40 million over the five-year period. The precise figure would depend upon what numbers would be used in Option 3 for past values of the DRP for a BEE. In oral submission, the AER indicated that their calculations of the effect would be $22 million over the five years: Transcript, p 157. There is debate about how to determine the appropriate numbers, and while this is relevant to the AER's stated reasons for its preference for Option 2, the appropriate method of determining such numbers is not a matter before this Tribunal.

211 SAPN asserts that the Final Decision of the AER involved error or errors of fact, an incorrect exercise of discretion, or was unreasonable. The errors asserted relate to each of the AER's considerations in choosing a transition method. These were given in the Final Decision (Attachment 3, pp 170-1) as:

- the impact on promoting efficient financing practices consistent with the principles of incentive based regulation;
- the impact on a BEE's opportunity to recover at least its efficient financing costs over the life of its assets;

- matching the allowed rate of return with efficient financing cashflows over a single regulatory period, and the potential conflict between this consideration and providing a BEE with a reasonable opportunity to recover efficient financing costs over the life of its assets;
- avoiding a potential bias in regulatory decision-making that can arise from choosing an approach that uses historical data after the results of that historical data is already known;
- avoiding the practical difficulties in the use of historical data to calculate the allowed return on debt, particularly during the global financial crisis.

Background

212 The NER (cl 6.5.2) provide rules for how the return on debt, as one component of the allowed rate of return, for a DNSP is to be determined and requires it must contribute to the allowed rate of return objective ('**ARORO**') which is defined in NER (cl 6.5.2.(c)) as:

> *The allowed rate of return objective is that the rate of return for a Distribution Network Service Provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service Provider in respect of the provision of standard control services (the allowed rate of return objective).*

213 Prior to rule changes in November 2012, the NER required that the return on debt must be the same figure for each year of the regulatory control period. In practice this was implemented through use of the "on-the-day" approach in which the return on debt for all years was determined as the prevailing cost of debt finance at the start of the regulatory control period (using an average over some agreed, preceding, number of days).

214 The rule changes allowed for the return on debt to be determined to be the same for each year of a regulatory control period, or to be different for each year (NER cl 6.5.2(i)) and, subject to contributing to the ARORO, NER cl 6.5.2(j) allowed for a methodology which resulted in the return on debt reflecting:

(a) the return that would be required by debt investors in a BEE if it raised debt at the time or shortly before the making of the distribution determination for the regulatory control period; or

(b) the average return that would have been required by debt investors in a BEE if it raised debt over an historical period prior to the commencement of a regulatory year in the regulatory control period; or

(c) some combination of the returns referred to in subparagraphs (a) and (b).

215 The 2012 changes included NER cl 6.5.2(k)(4) which required the AER to take into account any impacts on a BEE that could arise from a change in the debt estimation methodology. Clause 6.5.2(k) states that:

> *In estimating the return on debt under paragraph (h), regard must be had to the following factors:*
>
> *(1) the desirability of minimising any difference between the return on debt and the return on debt of a benchmark efficient entity referred to in the allowed rate of return objective;*
>
> *(2) the interrelationship between the return on equity and the return on debt;*
>
> *(3) the incentives that the return on debt may provide in relation to capital expenditure over the regulatory control period, including as to the timing of any capital expenditure; and*
>
> *(4) any impacts (including in relation to the costs of servicing debt across regulatory control periods) on a benchmark efficient entity referred to in the allowed rate of return objective that could arise as a result of changing the methodology that is used to estimate the return on debt from one regulatory control period to the next.*

216 It is noteworthy that while these requirements refer to a "benchmark efficient entity" there is no precise guidance given on the debt financing policy assumed to be followed by such an entity. Indeed NER cl 6.5.2(j) quoted above allows for virtually any pattern of financing of such an entity. The AEMC's rule determination (AEMC, Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012) noted at 7.4.1 (p 84) that "efficient benchmarking service providers may have different efficient debt management strategies". Moreover, NER cl 6.5.2(k) implies that it in adopting a change in methodology, consideration is to be given to the effect on a hypothetical "benchmark efficient entity", not the DNSP which is the subject of the determination. In practice, of course, it is possible that the DNSP could be such an entity.

217 Also NER cl 6.5.2(k)(1) and (4) are not specific to the time periods to which regard needs to be given. Thus, in subcl (k)(1), the minimisation between allowed and actual cost of debt (for a BEE) could refer to the regulatory control period, or to the life of the assets being (partially) financed by that debt. Similarly, subcl (k)(4) could be interpreted as referring to only the two regulatory control periods spanning the change in methodology, or to a longer period such as the life of assets. One component of the dispute between SAPN and the AER effectively relates to different interpretations of these rules, with the AER tending to focus on

effects over the life of the assets and SAPN focusing on the current regulatory control period. In the Final Decision (Attachment 3, p 153) the AER states that "[w]e discuss impacts that occur across regulatory control periods, such as over the life of a benchmark efficient entity's regulated assets. We consider the rules require us to do so." It is the view of this Tribunal that the conclusion of whether the AER committed errors or was unreasonable in making its decision on the transition process hinges upon the validity of this interpretation of the rules.

218 As noted above, the AER's decision to adopt Option 2 is consistent with its ROR Guideline published in December 2013, following a draft document in August 2013. There, the AER stated that it would henceforth use a trailing average portfolio approach for total debt costs following completion of a transitional period of 10 years (of the same form as that described for the risk-free component above). It argued that this approach would be adopted for all service providers and that doing so would contribute to confidence in the regulatory process. DNSPs would therefore have been aware of the intended change some 18 months before it was due to come into effect, enabling them to make some adjustments to debt portfolio financing arrangements in anticipation.

219 In its Explanatory Statement of the ROR Guideline (p 120) the AER referenced the AEMC commentary regarding the motivation for the 2012 changes allowing for the possibility of a transition period:

> *The purpose … is for the regulator to have regard to the impacts of changes in the methodology for estimating the return on debt from one regulatory control period to another. Consideration should be given to the potential for consumers and service providers to face significant and unexpected change in costs or prices that may have negative effects on confidence in the predictability of the regulatory arrangements. …*
>
> *Its purpose is to allow consideration of transitional strategies so that any significant costs and practical difficulties in moving from one approach to another is taken into account.*

220 In the ROR Guideline at 6.1, it is stated that:

> *The allowed return on debt must be estimated such that it contributes to the achievement of the allowed rate of return objective. It should therefore provide compensation to a service provider for the debt financing cost which is commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk.*

The regulatory decision process

221 SAPN provided its initial access proposal to the AER in October 2014, in which it proposed transitioning to the new trailing average approach for the cost of debt (SAPN, Regulatory

Proposal, pp 338-41). In that proposal the suggested approach involved direct reference to the cost of debt for a BBB rated entity rather than separate examination of risk-free and DRP components. This was, in effect, the Option 2 approach chosen by the AER (although it did not separately identify the risk-free and DRP components of borrowing costs), and was consistent with the AER's ROR Guideline. On 6 February 2015, before the AER's draft decision in this case, SAPN made a submission to the AER following the AER's November 2014 draft determinations for NSW DNSPs, which involved the adoption of Option 2. In this submission it recommended use of the hybrid (Option 3) approach.

222 In its Preliminary Decision in April 2015, the AER determined that Option 2, consistent with SAPN's original proposal, should be adopted. It commented that it was not clear that the NER allowed for SAPN to submit a changed proposal such as via its 6 February 2015 submission (SAPN Preliminary Decision, Attachment 3, p 129).

223 Subsequently in the Final Decision (Attachment 3, p 12) the AER noted:

> *In the preliminary decision we accepted SA Power Networks' initial proposal to adopt a transition applied to both the base rate and debt risk premium components of the return on debt. Under the normal decision making process, this means SA Power Networks could not change its position in the revised proposal. However, it appears the drafting of the transitional arrangements in the NER leads to an outcome which makes it possible for service providers to depart from their proposal after the AER has accepted it, and allows them to introduce a new position after the preliminary decision stage. Such an outcome raises concern on the relevance of the preliminary decision process.*

224 In its Revised Proposal submitted in July 2015, SAPN explained at p 380 that the significant fall in the DRP since submission of its initial proposal, and the implication of the high weight given to the "on-the-day" approach in the Option 2 transition process thus depressing the allowed rate of return was one reason for its changed position. It also argued that the hybrid Option 3 approach was more consistent with the efficient financing processes of a benchmark firm.

225 In its Final Decision, the AER reaffirmed its decision to use Option 2 as the transition method. Other issues where there were differences in method for determining the cost of debt between the AER decision and SAPN's Revised Proposal included adoption of a BBB+ rating rather than BBB rating for the BEE, and sources of, and required adjustments to, data for determining the DRP for 10-year debt of a BBB+ rated entity. These are not matters under review and thus do not need consideration here.

Debt financing practices and regulation

226 It is generally accepted that the debt financing practices of a regulated access provider will be influenced by the specific features of regulation. This is because the regulatory approach will determine the allowed cost of debt, and resulting revenue implications, based on its assumed financing method. Risks to the service provider of actual debt costs differing from the allowed cost (and thus revenue allowed) will arise from differences between the financing pattern adopted and that assumed in the regulatory process.

227 Under the previous "on-the-day" approach, an allowed return on debt was determined at the start of the regulatory control period and fixed for each of the years in that period. Under the building block approach, the allowed revenue over the period thus included an amount sufficient to meet interest payments on the debt financed component of the regulatory asset base in each year, calculated using that specified cost of debt figure (and specified leverage). If the entity had an actual cost of debt above or below that figure it would thus be, respectively, under-compensated or overcompensated for its debt financing costs during that regulatory control period.

228 To avoid that risk, one option would be for the DNSP to arrange its debt finance portfolio such that all debt would mature just prior to the commencement of a regulatory control period. It would then raise new debt at the same time – when the allowed cost of debt is determined. Doing so would, in principle, mean that its actual cost of debt would match the allowed cost in the new regulatory control period (or differ only to the extent that its debt costs were different to those of a BEE).

229 In practice, a number of complications mean that such an approach is unlikely to be consistent with efficient debt financing, and possibly infeasible. Particularly relevant to the current matter is the potential risks to the DNSP of attempting to refinance its entire debt portfolio at a specific point in time. It would then be subject to risk of adverse movements in its borrowing costs which are not compensated under the regulatory regime, which bases allowed cost of debt on that applicable to a BEE. Such risks could arise either from random shocks to the DRP of the issuer, unwillingness of investors to absorb a large volume of new debt from the issuer, or opportunistic behaviour by lenders aware of the issuer's debt rollover requirements. While regulatory agreement to use some private, pre-agreed, averaging period for calculating the cost of debt can mitigate some of this risk, the concentration of debt

rollover within a relatively short period is not generally accepted as good risk management practice.

230 Another complication was that, in the on-the-day approach, the AER based the cost of debt on an assumed 10-year maturity for debt, even though the regulatory control period was five years. Except in the highly unlikely event of five-year and 10-year debt having the same cost at the start of the regulatory control period, issuing five-year debt to match the five-year resetting of debt costs which occurs at the start of the next control, and thus hedge debt financing cost risks, would lead to actual debt costs differing from allowed debt costs. In general, given an historical tendency for an upward sloping yield curve (10-year rates greater than five-year rates), the DNSP issuing five-year debt would tend to have debt costs less than the corresponding allowable revenue, which might, to some degree, compensate for the rollover risks in such a strategy.

231 More generally, the DNSP's allowed revenue over the regulatory control period would also reflect debt (and equity) costs from new funding to meet new capex, but at the cost of debt allowed at the start of the regulatory control period. The actual cost of new debt funding during the period could be expected to differ from the allowed cost existing at the start of the regulatory control period creating risk for the DNSP. In principle, the DNSP could hedge that risk by entering derivative contracts at the start of the regulatory control period to lock in the cost of a future debt-raising. However, depending on the slope of the yield curve, the resulting cost could be above or below the allowed cost determined at the start of the regulatory control period, while uncertainties about the precise amount and timing of future debt financing also create risks for the DNSP.

232 Rather than attempting to structure its debt portfolio to mature and be rolled over at the start of the regulatory control period, a BEE might adopt an alternative approach to risk management. One such alternative approach for the DNSP is to arrange to have a maturity profile of debt which is relatively evenly spread over some horizon such as 10 years, and use derivative contracts to attempt to hedge the interest rate risk associated with the "on-the-day" determination of the allowable cost of debt. It might, for example, issue some amount of 10-year floating rate debt each year and enter interest rate swaps as the fixed rate payer/floating rate receiver at the start of each regulatory control period. Then, for example, if it had floating rate debt on issue with 7 years remaining maturity at the start of the regulatory control period, it could enter a five-year swap at that date to fix the cost of that debt for the

next five years. Then, at the start of the next regulatory control period it could enter another five-year swap which would fix the cost of that debt for the remaining two years of its life as well as fixing the cost of new floating rate debt to then be issued to replace it over the subsequent three years of the regulatory control period.

233 However, because available derivative contracts are based on “risk-free” benchmarks such as a bank bill swap rate or government security rate, only the risk-free component of the debt cost can be hedged in this way. The DRP component of borrowing costs which is determined at the time the debt financing is taken out, and applies for the term of the financing, cannot generally be hedged. Consequently, a DNSP which adopts a debt portfolio management strategy involving a staggering of debt maturities will remain exposed to the risk that the DRP “on-the-day” of determination of allowable cost of debt will differ from that applicable to its existing debt portfolio (as well as future rollovers of maturing debt during the regulatory control period).

234 The decision to move towards an allowable cost of debt determination based on the historical trailing average approach reflects recognition that this is more consistent with efficient debt management practices for a DNSP. With such a regulatory approach in place, the DNSP can minimize debt funding cost risks by creating a debt maturity (or repricing) profile consistent with that assumed by regulatory practice. Having 10% of its debt re-issued (or repriced) each year as 10-year debt would remove exposure to movements in both the risk-free component of debt costs and the DRP component applicable to a BEE. The DNSP would still face the risk that the DRP they were able to achieve was different from that applicable to a BEE.

Implications of past financing practices and the transition approach

235 A transition process for the risk-free component of debt costs is accepted by both parties as appropriate. The reason is that an immediate shift to the new approach could involve potentially costly unwinding of hedging contracts put in place to deal with the risks of on-the-day determination of debt costs.

236 But, as noted above, issues associated with unwinding hedge contracts are only relevant for the risk-free component of debt costs. DNSPs are locked into the DRP involved in their past funding decisions until those debt contracts mature.

237 The AER transition approach means that differences between the historical average DRP embedded in the debt portfolio of the DNSP as at the start of this regulatory control period

are not reflected in the DRP included in allowable cost of debt in the first year (since the on-the-day approach applies there). However, future DRP costs in rolling over existing debt and issuing additional debt are, in principle, fully included. This is because the DRP in each successive future year is included in the DRP component of allowable debt costs with a 10% weight, with the weight of the on-the-day DRP reducing by 10 percent.

238 Maintaining some weight for the on-the-day approach to the DRP component in the transition process means that the DNSP incurs higher or lower debt costs than allowed over this regulatory control period if the on-the-day DRP differs from the trailing historical average DRP costs embedded in its debt portfolio at the start of the regulatory control period. Consequently, if the historical trailing average DRP at the start of the regulatory control period exceeded the on-the-day figure (at the start of the regulatory control period) the allowable revenue in that regulatory control period would be higher in each year from immediately shifting to Option 3, and vice versa if it were lower. In the current case the historical average exceeds the on-the-day figure implying higher revenue from Option 3 over the current regulatory control period, and in submissions SAPN provided evidence that this would also apply over the subsequent regulatory control period.

Efficient investment and the regulatory approach to debt costs

239 NER cl 6.5.2.(k)(3) requires that in setting the cost of debt consideration be given to "the incentives that the return on debt may provide in relation to capital expenditure over the regulatory control period, including as to the timing of any capital expenditure". While the historical trailing average approach is more compatible with actual debt management practices, it might be thought to be less consistent with determination of a cost of capital, and allowable revenue and prices, required for efficient investment decisions.

240 By using an on-the-day approach to determine cost of capital and thus allowable revenues, the outcome – in theory at least – is that the DNSP can expect a revenue stream consistent with what a competitive market would generate. Capital investment decisions made at that date which meet a positive NPV condition using the allowed rate of return would be efficient, based on current conditions in the market for funds. In contrast, if the DNSP assessed capital investment options by reference to the rate of return incorporating debt costs allowed from the trailing average approach, inefficient investment decisions could result.

241 For example, suppose allowable revenues for a very short-term project were based on historical funding costs, and those were above current market funding costs. By undertaking

that project abnormal profits could be made, because allowable revenue implies a positive NPV when evaluated at current market funding costs. However, it is by no means clear that a sophisticated DNSP would make investment decisions for the very long-lived assets required for its operations based on past financing costs rather than current and expected future financing costs. It is the latter which determine, through the building block model, future expected cash flows over the long horizon involved. Nor should it be expected that regulatory approval for capex plans would be based on an appraisal using historical funding costs rather than current market conditions.

242 Also relevant in this context is the fact that the building block model using the on-the-day approach implies a NPV=0 condition at that date, in the sense that expected cash flow streams from current assets or new capex are just sufficient to match required returns of investors. However, financial market conditions can change substantially over the five-year horizon of a regulatory control period such that using the allowed cost of capital to assess potential investments during the period could, again, lead to inefficient decisions. However, to the extent that investments are very long-term (eg 80 years), and future cash flows linked to future changes in cost of capital (at the start of each regulatory control period, or over a 10-year historical trailing average) it is not obvious that a sophisticated DNSP would act in this manner.

243 The approach to debt costs also affects the risk facing the DNSP from investment decisions, although there is no evidence provided to the Tribunal that those risks would be systematic and thus affect the cost of capital. Under the on-the-day approach, a DNSP which adopts a staggered-debt financing approach experiences random differences between actual and allowed cost of debt (and thus revenue) over the life of an investment. Arguably, these differences could be expected to average out to zero over the long term, and are not systematic risks which would lead to a higher cost of equity capital than if a trailing historical average approach were used.

244 While the transition approach used will have implications for the extent to which past differences in debt costs are locked in or averaged out over the transition period, and affect DNSP profitability over that period, that is not relevant to forward looking investment decisions. Because the choice between the trailing historical average and on-the-day approaches to the costs of debt should not affect long-term investment decisions, the form of

transition should also have no material implications for the efficiency of future investment decisions.

Alleged errors in the Final Decision

245 SAPN argues that the AER decision to not adopt an immediate change to a trailing average approach (Option 3), and instead deciding on a gradual transition approach (Option 2), for the DRP component of the allowable cost of debt was wrong on each of the five considerations involved. These were outlined at Attachment 3, p 149 (and presented slightly differently in several cases at pp 170-1) of the Final Decision. It is appropriate to adopt a different ordering to that contained in the Final Decision reflecting the logic and approach applied by the Tribunal in considering the arguments. It is noticeable that the considerations on pp 170-1 make several references to the consideration of recovering efficient financing costs over the life of its assets, and this permeated the AER discussion in the Final Decision. This emphasis on considerations relevant to "life of assets" rather than just the current regulatory control period is an important one raised by SAPN.

Promotion of efficient financing practices

246 One consideration listed by the AER was "the impact on promoting efficient financing practices consistent with the principles of incentive based regulation". The AER accepts that both Option 2 and Option 3 are consistent with this consideration (AER's Outline of Submissions, p 51). SAPN focuses in its submission (Section C.4(a)) on the impact of the choice of transition approach on the consequences of past efficient financing practices for the revenues of the BEE in the current (and future) regulatory control periods. It is true that the consequences of past efficient financing practices are affected by the choice of transition arrangement (since the allowable cost of debt in the forthcoming regulatory control period(s) differs) but this has no consequences for choices regarding future practices. But SAPN provides no explanation as to how future financing arrangements would be affected in a manner inconsistent with this consideration by the choice of transition approach. Indeed, the arguments advanced by SAPN about inability to hedge the DRP component of existing debt costs suggests that these are akin to "sunk costs" and, while relevant to profitability impacts from the choice of transition are not relevant to future debt financing decisions. The Tribunal is of the view that the AER committed no error of fact, incorrect exercise of discretion, or was unreasonable in reaching its conclusion that both Options 2 and 3 were consistent with this first consideration.

Bias in regulatory decision-making

247 Another consideration of the AER was avoiding "a potential bias in regulatory decision-making that can arise from choosing an approach that uses historical data after the results of that historical data is already known". SAPN argues in its Outline of Submissions (at para 279) that the AER made an error of discretion and was unreasonable in preferring Option 2 over Option 3 on this basis because:

> *(a) the AER was incorrect to find that it was a desirable feature of the AER transition that it avoided a relevant bias in regulatory decision making;*
>
> *(b) the AER was incorrect to find that the hybrid transition gave rise to a relevant bias in regulatory decision making; and*
>
> *(c) concerns as to the nature of the bias raised by the AER were not relevant to, and could not override, the requirement of cl 6.5.2, to estimate the return on debt for a regulatory year such that it contributes to the achievement of the allowed rate of return objective.*

248 It is hardly surprising that in proposing a one-off transition arrangement in moving from one procedure for choosing the cost of debt to an alternative procedure, a DNSP would prefer and recommend the option which, given the information available, is to its advantage. In this case, Option 3 is clearly preferable to the DNSP because the immediate adoption of the historical trailing average means that the DRP component of debt costs over the regulatory control period will reflect higher past values of the DRP. Chairmont Consulting provided evidence to the AER that had the transition process started between 2011 and 2014, the historical pattern of the DRP would have led to the opposite outcome: Final Decision, Attachment 3, p 149. In contrast, the Option 2 transition does not incorporate those historical values. Future values of the DRP impact equivalently on the allowable DRP component of debt costs in future years under both Option 2 and Option 3.

249 The answer to the contentions of SAPN is that the AER's approach involved "starting with an on-the-day rate and gradually transitioning to the trailing average approach (Option 2) [which] only uses averaging periods for each year that are nominated in advance" (Final Decision, Attachment 3, p 192).

250 The Tribunal is of the view that this approach is a valid one, involving the AER considering alternative transition approaches to the one proposed by SAPN, in order to avoid a bias in regulatory decision-making. In determining which among the alternative transition options should be chosen, the AER was endeavouring to reach a decision that contributes to the ARORO. This approach by the AER was correct.

Historical data problems

251 Another consideration listed by the AER was avoiding "practical problems with the use of historical data as estimating the return on debt during the global financial crisis is a difficult and contentious exercise" (Final Decision, Attachment 3, p 149). Use of Option 3 would require use of such data, whereas Option 2 avoids the need to consider such historical data. The AER noted that this was a relatively minor issue compared to other considerations.

252 It is the case that there are some difficulties in accurately determining what the historical DRP on 10-year debt issued by a "BBB+" rated BEE would have been in each of the 10 years preceding the start of the current regulatory control period. Two factors are relevant.

253 First, this period incorporates the global financial crisis which meant that the DRP on outstanding bonds and new bond issues was significantly elevated in the years following 2007 when financial markets were disrupted. While the DRP on loans from banks can also be assumed to have increased at that time, there is no readily available evidence on whether the increase was higher or lower than that seen in bond markets. And it could be anticipated that the efficient financing practice for a BEE would have involved choosing to raise debt finance through the cheaper of the two alternatives (debt issue or bank loan). This might suggest that DRP figures from the bond market might be an upper bound on the achievable DRP unless there was significant use of the bond market by comparable entities at that time. On the other hand, given elevated borrowing costs, efficient financial management may have involved greater temporary use of equity financing (such as via increased earnings retention) rather than use of debt markets. Alternatively, at times when the DRP was perceived to be unusually and temporarily high, shorter-term debt might have been used to avoid locking in that high level of DRP.

254 These considerations suggest that observable DRP figures from this period might be noisy estimates of the DRP (both in terms of the percentage cost and also actual dollar cost if leverage changed temporarily) of a BEE. However, this is no different in principle to potentially similar problems in accuracy of DRP estimation which may occur in future years. Moreover, such data was used in the previous AER determination of cost of debt for the regulatory control period 2010-2014, suggesting that concerns about the validity of the historical data from that date onwards should not be paramount. Arguably, estimating appropriate DRP figures for the preceding several years (2007-2009) associated with the financial crisis may be problematic and contentious. However, this is not an argument for not

incorporating such data, particularly since it is eventually phased out of the trailing historical average.

255 A second issue is the robustness of the interest rate data available from providers of such data for the use required here. Several commercial providers track returns on corporate debt of issuers of different credit ratings. However, there are relatively few domestic corporate bond issues in Australia, and their remaining maturity is extremely unlikely to be exactly 10 years. Consequently to estimate the yield and DRP on a 10-year maturity of a BBB+ rated entity requires a number of approximations, including interpolation or extrapolation of rates or DRPs available for different maturities. The complexities are well outlined in the Final Decision, Attachment 3, pp 197-200. In response, SAPN notes (Outline of Submissions, C4(e)) that alternative approaches involving averaging of various sources do not involve major differences in estimates when averaged over a number of years.

256 There can be significant debate about the merits of alternative approaches. The Tribunal notes that the issue of extracting reasonable estimates of the historical DRP from available, but non-robust, past data appear inherently no more problematic than estimating many other inputs into the PTRM such as the current cost of equity or the valuation of imputation credits.

257 The Tribunal is of the view that while there are undoubtedly problems with obtaining accurate estimates of the DRP of a BEE over earlier years of the decade prior to the start of the regulatory control period, this is not a sufficient reason to reject the use of the Option 3 transition approach. The Tribunal does not accept that the AER was in error or its decision was unreasonable in considering the reliability of the historical information.

Impact of change on BEE and recovery of efficient financing costs

258 The Tribunal's analysis of the three preceding contentions does not demonstrate the errors claimed by SAPN. Thus the matter hinges on the final two considerations.

259 The final two considerations listed by the AER are somewhat interrelated, and dependent upon a common item. That common item is the question of whether the application of the reference to "across regulatory control periods" should refer solely to the periods before and after the change in methodology, or involve a longer horizon. This involves looking at the NER as a whole. Also important is the question of whether the choice of transition approach creates or enshrines "windfall gains or losses" to either the DNSP or its customers which are inconsistent with incentive based regulation.

260 The relevant considerations in its approach listed by the AER affecting this issue are having regard to (a) "the impact on a benchmark efficient entity of changing the method for estimating the return on debt in one regulatory control period to the next" and (b) that it "provides a benchmark efficient entity with a reasonable opportunity to recover at least the efficient financing costs it incurs in financing its assets. And as a result it: [p]romotes efficient investment, and [p]romotes consumers not paying more than necessary for a safe and reliable network" (Final Decision, Attachment 3, p 149).

261 This latter consideration is alternatively expressed by the AER as consideration of "matching the allowed rate of return with efficient financing cashflows over a single regulatory period, and the potential conflict between this consideration and providing a benchmark efficient entity with a reasonable opportunity to recover efficient financing costs over the life of its assets" (Final Decision, Attachment 3, pp 170-1).

262 In assessing the arguments, it is useful to refer to the NER which states that in determining the return on debt regard must be had to "the desirability of minimising any difference between the return on debt and the return on debt of a benchmark efficient entity referred to in the allowed rate of return objective" (NER cl 6.5.2(k)(1)) and "any impacts (including in relation to the costs of servicing debt across regulatory control periods) on a benchmark efficient entity referred to in the allowed rate of return objective that could arise as a result of changing the methodology that is used to estimate the return on debt from one regulatory control period to the next." (NER cl 6.5.2(k)(4))

263 It has been already noted that the AER, in deciding to move to a trailing historical average approach, has adopted a perspective that a characteristic of a BEE is that it would (a) adopt a financing policy involving a staggered-debt portfolio, and (b) hedge the risk-free component of debt costs associated with the on-the-day approach through use of swaps (Final Decision, Attachment 3, p 551). That would leave that entity exposed to differences arising between the average historical DRP embedded in its debt portfolio and the on-the-day DRP. If the embedded DRP exceeds the on-the-day figure the allowed revenue for debt costs would not cover actual costs, and vice versa. For such an entity, NER cl 6.5.2(k)(1), if considered in isolation and interpreted as referring to minimizing year-by-year differences, would imply that Option 3 would be the appropriate choice.

264 SAPN (Outline of Submissions, paras 232 and 248) notes that:

The AER's interpretation of the factor in clause 6.5.2(k)(1) is not a matter in dispute, save that SA Power Networks contends that it is properly applied on a forward-looking basis in each year of the regulatory control period. That is, the factor is properly understood as requiring regard to be had to the desirability of minimising any difference between the return on debt allowance the AER sets for each year of the relevant regulatory control period (the allowed return on debt) and the cost of debt a benchmark efficient entity would incur each year of that regulatory control period, based on the AER's assumptions of the efficient financing practices of a benchmark efficient entity (the actual return on debt). …

SA Power Networks contends that it is plain that rate of return objective requires the return on debt to be estimated so that the return on debt is commensurate with the efficient financing costs that a benchmark efficient entity would incur each year over the relevant regulatory control period.

265 SAPN argues that (at para 247), in contrast:

the justification that appears to be proffered by the AER in the Final Decision is that the NER only require compensation for efficient financing costs over a longer period referred to as "the life of the relevant assets".

266 In this regard NER (cl 6.5.2(k)(4) also requires consideration of the impact on cost of servicing debt across regulatory control periods. The AER applies the notion of "across regulatory control periods" as extending beyond the two periods immediately before and after the change in regulatory methodology and referring to "the life of the relevant assets". Consequently, it argues that in taking a longer perspective differences in the allowed and actual cost of debt in individual years and over regulatory control periods under the on-the-day approach can be expected to balance out over time. The historical trailing average approach also achieves that balance of allowed and actual cost of debt over the longer time horizon, but also on a year-by-year basis.

267 In its Final Decision (Attachment 3, p 167) the AER stated that "[w]e consider the efficient debt financing costs of a benchmark efficient entity as those which are expected to minimise its debt financing costs over the life of its assets, while managing refinancing risk and interest rate risk".

268 The AER argues at pp 174-5 that this is equivalent to applying the NPV principle which it defines as follows:

The NPV principle is that the expected present value of a benchmark efficient entity's regulated revenue should reflect the expected present value of its expenditure, plus or minus any efficiency incentive rewards or penalties. In other words, departures from cost recovery are acceptable and desirable, so long as they are the result of management induced efficiencies or inefficiencies, rather than windfall gains or losses. Windfall gains or losses would result in a service provider being over- or under-compensated for its efficient costs. The building block model which the NGR require us to use is based on this principle.

269 The Tribunal is of the view that the AER has not erred in applying the provision of NER cl 6.5.2(k)(4) in referring to a longer time period, such as that involved in recovery of efficient financing costs over the life of the asset. The theoretical basis of the PTRM and the NER are premised on such an approach which involves determining allowable cash flows such that an NPV=0 condition is met ex ante. It is true that this NPV=0 condition is implemented via the PTRM so as to apply as at the start of each regulatory period for that period. However, the inclusion of the end of period regulatory asset base in that calculation (such that the opening regulatory asset base equals the present values of cash flows plus end-of-period regulatory asset base) implies that this is only one stage in a sequence of such decisions aimed at achieving NPV=0 over the life of the assets.

270 A BEE may adopt a different financing structure to that implied in the PTRM calculation, such as using a staggered-debt portfolio rather than an on-the-day rollover approach. This could lead to it facing a non-zero NPV situation for any regulatory period. But it can be assumed that it would only do so if it anticipated that over the longer term (life of the assets) such non-zero NPV situations would tend to balance out.

271 This interpretation of NER cl 6.5.2(k)(4) has two consequences. First, it means that the argument of SAPN that Option 3 involves smaller year-by-year differences between the actual cost of debt and that allowable over the current regulatory control period is not, of itself, sufficient to prefer Option 3 over Option 2. Second, it then requires identifying whether one of the two transition options is more consistent with recovery of efficient financing costs over the life of assets, or involves impacts on the BEE which are judged to be, in the context of the NEL objectives, worse. Unfortunately, in this regard, the NER cl 6.5.2(k)(4) provides no guidance on how to assess such impacts. Nor is such criteria explicitly specified in the NEL. Section 7A(2) of the NEL provides:

> *A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in–*
>
> *(a) providing direct control network services; and*
>
> *(b) complying with a regulatory obligation or requirement or making a regulatory payment.*

272 At s 7A(3) a further consideration relevant to this situation is specified as:

> *… The economic efficiency that should be promoted includes–*
>
> *(a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and*

> (b) *the efficient provision of electricity network services; and*
>
> (c) *the efficient use of the distribution system or transmission system with which the operator provides direct control network services.*

273 Section 7A(2) does not imply recovery of costs within a particular regulatory control period such that the AER focus on "the life of the asset" is not inconsistent with the NEO. Section 7A(3)(c) indicates that in determining allowable revenue and prices, the AER should take into account the impact of its decisions on demand for electricity network services. Thus it would be appropriate for the AER to consider impacts both on consumers and DNSPs in arriving at a decision on the choice of transition approach.

274 The AER's argument that Option 2 is better aligned with the NEO than is Option 3 is based on consideration of the effects of the transition on a BEE which had adopted a staggered-debt portfolio approach under the previous on-the-day regime. There is no dispute that this is a suitable characterisation of a BEE, and that the BEE would be able to hedge the resulting risk on the risk-free component of its debt, but would be subject to the risk that the DRP allowed for any regulatory control period differed from its actual embedded DRP for that period.

275 The AER argues (in its Outline of Submissions at para 185) that regulatory decisions which generate windfall gains or losses (to either DNSPs or their customers) are undesirable:

> *The AER observed that departures from cost recovery are acceptable and desirable so long as they are the result of management induced efficiencies or inefficiencies, rather than windfall gains or losses.*

276 In the Final Decision, there is considerable discussion about whether allowed DRPs differed from actual DRPs over past regulatory control periods, and SAPN focuses on this as the potential source of windfall gains or losses. It argues that there is no authority for subsequent "squaring up" which it interprets the AER decision as involving. That argument implies that an allowed DRP less than the actual (of a staggered-debt portfolio) in the current regulatory period under Option 2 is offsetting the reverse situation in previous periods. SAPN stated in its Outline of Submissions (at para 264) that:

> *Even if it was permissible for the AER to have regard to the motion of the balance of under and over recovery over time (which it is not, for the reasons discussed above), as the AER's Final Decision would result in a benchmark efficient entity in the position of SA Power Networks facing the costs of a trailing average DRP which is in excess of the prevailing DRP, the AER can only reach a conclusion that its transition provides a benchmark efficient entity with a reasonable opportunity to recover at least efficient costs if it is satisfied that:*
>
> > (a) *a benchmark efficient entity in the position of SA Power Networks would, at the beginning of the 2015-20 regulatory control period,*

have an accumulated gain comprising the difference between the DRP costs it had faced in the past and the regulatory allowance provided for this component of the return on debt; and

(b) the AER transition will erode that accumulated gain to zero (and no more or less) over the course of the AER's transition.

277 SAPN argued at para 252 that:

> *cl 6.5.2 of the NER must be interpreted as requiring a return that is sufficient to recover efficient financing costs in each regulatory year of the regulatory control period. Neither the NER or the Law permit the AER to reduce the return on debt allowance below the level of efficient financing costs in an attempt to "claw back" or square-up differences between the allowed return on debt and the return on debt faced by a benchmark service provider in a previous regulatory period.*

278 There is some lack of clarity in the AER's discussion of this issue. For example, in the Final Decision (Attachment 3, pp 562-3) the AER argues that:

> *a consistent application of either the on-the-day or trailing average approach … promotes revenue with an expected present value equal to the present value of the entity's efficient costs. This outcome is consistent with the NPV principle which we discussed further below. However, when the method to estimate the return on debt changes during the life of regulated assets; the NPV principle is unlikely to hold automatically. Any existing accumulated differences between the allowed and actual return on debt of a benchmark efficient entity would remain. As a result, the service provider will receive a return on debt that is different from that of a benchmark efficient entity, and consumers will pay prices that reflect this difference.*

279 It is possible to interpret the above statement as referring to past gains or losses as at the date of switching from an existing regulatory approach to another approach That would prompt a focus on how a particular transition process would, or would not, involve some "squaring up" element. However, while the AER devoted considerable space to discussing the past behaviour of the DRP, this was not an apparent consideration in its preference for Option 2. In its Final Decision (Attachment 3, p 569) the AER states that, despite examining the issue and available data "we have not relied on analysis of whether our transitional approach will erode past windfall gains or losses in making our decision".

280 Rather the AER's approach is premised on examining whether a particular transition approach would itself create "windfall gains or losses" arising over the current (and subsequent) transition period. Its approach is based on analysis of the NPV=0 principle underlying the PTRM, which implies that for each component of costs (return on capital, return of capital, opex etc), a corresponding component of the revenue stream with zero anticipated NPV is allowed. It then considers the total debt portfolio of a BEE as a set of

annual tranches of debt issued in each of the past 10 years and examines the consequences of a transition approach for each of those tranches.

281 As previously outlined, under the previous "on-the-day approach" a BEE which refinanced all debt at the start of the regulatory control period would be assured of allowed debt costs equal to actual during that period. In contrast, a BEE which adopted a staggered-debt portfolio (and hedged the risk-free component) would accept risks of future deviations of actual embedded debt costs from allowed debt costs. Over the long-term (such as the life of assets) these deviations might average out as debt raised in a particular year matures and is refinanced at prevailing rates.

282 Once a shift to the historical trailing average approach is completed there is no annual divergence between allowed and actual debt costs for each annual tranche of debt issued by the BEE.

283 The AER argues that, under the on-the-day approach, such a BEE would have anticipated that each annual tranche of debt could have experienced future differences between the allowed and its actual debt cost. For example, a BEE which issued 10-year debt seven years prior to the start of the current regulatory control period would have expected that the allowed DRP for the remaining three years to maturity of that debt would be set under the on-the-day approach and could differ from its actual DRP.

284 Thus if the allowed DRP on that tranche of debt is set according to a different rule during the transition period, a different outcome to that based on the anticipated application of the existing rule when the debt was issued would occur as a result of the regulatory decision. In this sense, there would be "windfall gains or losses" on that tranche of debt occurring during the transition period. Option 2 avoids this outcome for previously issued debt. It also means that debt which is issued (either new debt to fund capex or rolling over of maturing debt) in the transition period would have no difference between allowed and actual debt costs over the term of that debt.

285 The AER stated in its Final Decision (Attachment 3, p 158):

> *Our approach is designed such that service providers will face the outcomes on their debt raising decisions consistent with the expectations when that debt was issued. That is, for debt issued under the previous return on debt regime, outcomes will be consistent with those that would have arisen under the previous regime. For debt issued under the new regime, outcomes will be as per the trailing average portfolio. We are satisfied this approach achieves the NPV=0 principle in expectation, and is*

symmetrical and unbiased.

286 The AER argues that this is consistent with principles of incentive regulation, where a BEE adopting a staggered-debt portfolio approach under the on-the-day approach took financing risks from which it might gain or lose. It stated in its Final Decision (Attachment 3, p 173):

> *One of our reasons for this approach is so service providers face the financial outcomes of their past financing decisions, whether positive or negative, consistent with the principles of incentive regulation. …*
>
> *Accordingly, the impact on a benchmark efficient entity is not, in principle, different to the impact on a benchmark efficient entity if we had continued to adopt the on-the-day approach. This means that there is a minimal impact on the level of financial risk faced by a benchmark efficient entity as a result of changing the return on debt methodology from one regulatory control period to the next.*

287 At Attachment 3, pp 181-2, the AER argued its preference for Option 2 as:

> *In these circumstances, departures from the NPV principle do not result from efficiency gains or losses, but from changing the regulatory regime. For this reason, we consider the resulting benefits or detriments are windfall gains or losses that the change in methodology for estimating the return on debt should avoid. In other words, regardless of who faces the benefit or detriment, an immediate change from one return on debt method to another could have undesirable consequences. This possibility should concern both service providers and consumers. This is because, prior to a change in method occurring, neither could know whether they would face a benefit or detriment.*

288 The AER had, in its ROR guidelines, flagged that a gradual transition (equivalent to Option 2) was its intended approach because it would reduce the potential for "windfall gains or losses" arising from the change in regulatory approach impacting adversely on either consumers or the BEE (and to the benefit of the other). The Tribunal accepts that this position, stated well before this regulatory determination, is consistent with the NEO, and thus preferable to the alternative (Option 3).

289 The Tribunal is of the view that the AER has committed no error of fact or been unreasonable in reaching the conclusion that Option 2 is preferable on grounds of the "impact of change on benchmark efficient entity and recovery of efficient financing costs". Its interpretation of "across regulatory periods" as involving more than just the periods immediately surrounding the change in regulatory approach, and leading to consideration of effects over the life of the asset, is consistent with the NER. That justifies the attention paid by the AER to the NPV=0 criterion, which in turn leads it to consider whether one particular transition approach is more consistent with that criterion than the other. In that regard, it does not undertake a comparison based on offsetting historical excesses or deficiencies in the allowed DRP relative to actual. Rather, it assesses which approach is more consistent with meeting

expectations held of how future DRP values would be determined when particular annual tranches of debt were issued. It concludes, correctly in the view of the Tribunal, that Option 2 is preferable in that regard because it does not create windfall gains or losses in the current regulatory period from the regulatory change.

290 The grounds of review on the cost of debt are rejected.

Forecast bushfire safety capex

291 In its Revised Proposal, SAPN proposed a $40.6 million bushfire mitigation capex program (‘**Bushfire Mitigation Capex Program**’).

292 The Bushfire Mitigation Capex Program comprised three measures:

- replacement of manual 33kV, 19kV and 11kV reclosers with fast operating supervisory control and data acquisition (‘**SCADA**’) controlled enabled reclosers at a proposed capital cost of $18.1 million;
- replacement of rod air gaps (‘**RAG**’) and current limiting arcing horns (‘**CLAH**’) with modern surge arrestors at a proposed capital cost of $12.4 million; and
- reconstructing metered mains at a proposed capital cost of $10.1 million.

293 These measures were intended to limit fire-starts caused by SAPN’s distribution system in high bushfire risk areas (‘**HBFRAs**’).

Reclosers, RAGs and CLAHs

294 The following technical features and operation of reclosers, RAGs and CLAHs are uncontroversial. The description of those systems which follow is taken largely from SAPN’s written submissions.

295 Reclosers are self-contained pole mounted circuit breakers with inbuilt fault detection mechanisms and control systems. For transient faults, reclosers interrupt supply allowing the fault to clear and then automatically reclose to restore supply. For permanent faults, the recloser trips and remains open or “locks out” until the line is patrolled and confirmed as safe to restore supply.

296 SAPN has many manual 33kV, 19kV and 11kV reclosers in service that are part of its protection system to minimise the risk of injury and damage from an electrical fault and to limit the interruption of supply caused by a fault.

297 The operating system in manual reclosers is predominately hydraulic for fault detection and operation. SAPN says that the limitations of these units, compared with modern units, include slower fault clearing times, inflexible protection and control settings and an inability to remotely monitor or control their operation.

298 SAPN says that many of the reclosers can only be operated manually with the result that crews are required to attend multiples sites in rural locations over a short time frame. Under common circumstances, this process is practically difficult to implement in the required time frame. In addition, SAPN says it will not send its crews into dangerous situations on "catastrophic" bushfire days. This, it says, further limits the number of reclosers that can be manually operated on high bushfire risk days. SAPN argues that these difficulties can be overcome through investment in remote controlled SCADA reclosers.

299 SAPN maintains that these changes would bring it in line with current good electricity industry practice and significantly reduce the risk of fire-starts when faults occur.

300 RAGs and CLAHs are intended to protect equipment from the effects of overvoltages.

301 SAPN submits there is evidence that failures have occurred to overhead line equipment forming part of SAPN's distribution system because RAGs and CLAHs have been:

- bridged by animals or birds, resulting in them being electrocuted and falling to the ground and starting fires; or
- struck by lightning, causing hot metal particles to fall onto dry ground, igniting local grasses and vegetation.

302 In order to mitigate this risk, SAPN proposed to replace RAGs and CLAHs with modern surge arrestors. SAPN believes this would deliver clear reductions in the number of arcing events when these devices are bridged by animals or birds, or when lightning strikes.

Application of the NER

303 It is important to note that the AER's decision in relation to the Bushfire Mitigation Capex Program is only one component of the AER's overall decision in relation to forecast capex.

304 Under cl 6.12.1(3) of the NER, the AER's determination must include a decision in which the AER either:

> *(i) acting in accordance with clause 6.5.7(c), accepts the total of the forecast capital expenditure for the regulatory control period that is included in the*

current building block proposal; or

(ii) acting in accordance with clause 6.5.7(d), does not accept the total of the forecast capital expenditure for the regulatory control period that is included in the current building block proposal, in which case the AER must set out its reasons for that decision and an estimate of the total of the Distribution Network Service Provider's required capital expenditure for the regulatory control period that the AER is satisfied reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors …

305 Clause 6.5.7 of the NER applies to the approval of a DNSP's forecast capex. Clause 6.5.7(a) addresses the capex objectives, namely:

> *(a) A building block proposal must include the total forecast capital expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of the following (the capital expenditure objectives):*
>
> *(1) meet or manage the expected demand for standard control services over that period;*
>
> *(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;*
>
> *(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:*
>
> *(i) the quality, reliability or security of supply of standard control services; or*
>
> *(ii) the reliability or security of the distribution system through the supply of standard control services,*
>
> *to the relevant extent:*
>
> *(iii) maintain the quality, reliability and security of supply of standard control services; and*
>
> *(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and*
>
> *(4) maintain the safety of the distribution system through the supply of standard control services.*

306 Clause 6.5.7(c) directs the AER to consider whether proposed capex meets the capex criteria. It provides:

> *The AER must accept the forecast of required capital expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast capital expenditure for the regulatory control period reasonably reflects each of the following (the capital expenditure criteria):*
>
> *(1) the efficient costs of achieving the capital expenditure objectives;*
>
> *(2) the costs that a prudent operator would require to achieve the capital expenditure objectives; and*

> *(3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.*

307 In making its decision under cl 6.5.7(c) the AER must have regard to the capex factors listed in cl 6.5.7(e). The AER is also required to:

- make the decision in a manner that is likely to contribute to the achievement of the NEO set out in s 7 of the NEL;
- take into account the RPP specified in s 7A of the NEL; and
- ensure that SAPN (among others) is informed of material issues under consideration by the AER, and given a reasonable opportunity to make submissions in respect of the determination before it is made, under s 16(1)(b) of the NEL.

The AER's final decision on bushfire mitigation capex

308 The AER did not accept SAPN's capex proposal to spend $40.6 million, (or $38.9 excluding overheads) on its Bushfire Mitigation Capex Program. The AER was not satisfied that SAPN's proposed forecast reasonably reflected the capex criteria.

309 Instead the AER made a decision estimating the total of SAPN's required capex for the regulatory period that it considered reasonably reflected the capex criteria. The AER included $21.3 million in its decision, being an amount proposed by SAPN for its "core safety" program (which included substation fencing and security, sub-station earthing, sub-station lighting and CBD fault level control).

310 The AER's estimate of total forecast capex comprises a number of categories or "drivers" of capex. Those categories are set out in Table 6.3 of its Final Decision. Those categories include augmentation ('**augex**'), connections, replacement ('**repex**') and non-network capex.

311 In reaching its decision the AER said (Final Decision, Attachment 6, pp 81-2):

> *We are not satisfied that the additional capex for the proposed bushfire mitigation program is efficient additional capex that the prudent operator would require to maintain the reliability and safety of the network, or to comply with regulatory obligations or requirements. As such, we do not accept SA Power Network's capex proposal to spend $38.9 million on its bushfire mitigation program. We find that SA Power Network's Revised Regulatory Proposal, and our alternative estimate, already factor in a sufficient level of capex related to its business-as-usual bushfire risk management.*
>
> *As we noted in the preliminary decision, the evidence before us indicates that SA Power Networks is meeting its existing obligations, and historically, its bushfire risk management has been effective. The Office of the Technical Regulator has confirmed that SA Power Networks currently satisfies existing regulations and standards*

relating to managing bushfires.

312 The AER provided a summary of its decision immediately following this conclusion (at pp 82-3). It is helpful to reproduce that summary as much of it is specifically challenged by SAPN:

In summary we consider that:

- *The information before us does not satisfy us that section 60 of the SA Electricity Industry Act requires SA Power Networks to incur bushfire mitigation capex, in addition to capex that it may be required to incur in order to comply with other, more specific requirements under the SA Electricity Industry Act.*
- *contrary to SA Power Networks' assertion, the information before us does not demonstrate that the practices now adopted by Victorian networks are required to be adopted in order for a prudent South Australian network operator to achieve the capex objectives. SA Power Networks' bushfire risk and network construction is different from its Victorian counterparts.*
- *SA Power Networks is in a position to manage an increase in bushfire risk if it eventuates, given its legislated power to cut off the power to specific parts of the network in high bushfire risk situations.*
- *SA Power Networks has improved its fire start performance to date with business-as-usual expenditure, in compliance with its obligation under the NER to maintain the safety of the distribution system*
- *SA Power Networks has maintained its compliance with its obligations under the Work Health and Safety Act, and there is no indication that the Act will be amended to increase SA Power Networks' obligations.*
- *contrary to SA Power Networks assertions that a cost/benefit analysis for the bushfire mitigation program is not feasible, it could have provided a cost benefit analysis based on the 'As Low As Reasonably Practical' risk mitigation principle.*
- *while we accept that SA Power Networks proposed SCADA reclosers program may mitigate fire start risks, we have provided funding for the replacement of aging reclosers in our repex allowance.*
- *the proposed surge arrestors program is not efficient capex that a prudent network operator would need to make to achieve the capex objectives. Further, SA Power Networks has been given additional repex that addresses increased asset replacement needs.*
- *the proposed metered mains project is not efficient capex that a prudent network operator would incur .*

313 For these reasons the AER concluded that SAPN's capex for the Bushfire Mitigation Capex Program did not satisfy the capex criteria.

Areas of dispute

314 It is undisputed that the AER assessed SAPN's proposed Bushfire Mitigation Capex Program in two steps. First it assessed SAPN's compliance with its safety related obligations and its ability to manage bushfire risk. Secondly it assessed the prudency and efficiency of the bushfire mitigation projects, relevantly the SCADA reclosers and surge arresters.

315 Following this approach, the AER provided nine reasons for its decision – reproduced in the summary above. The first eight of these reasons (the ninth – the metered mains component – not being pressed here) are reproduced in SAPN's Amended Application and dealt with extensively in the written submissions of both parties.

316 SAPN argues that the relationship amongst these eight reasons does not clearly emerge from the AER's decision. That it is unclear, among other things, whether the AER considers that each of the reasons is individually sufficient to produce the result that the AER was not satisfied with the Bushfire Mitigation Capex Program.

317 SAPN is also critical of the AER's failure to identify how each of these reasons relates to the matters to which the AER was required to have regard, namely the capex objectives and the capex criteria.

318 In its Amended Application at para 142, SAPN contends that the Bushfire Mitigation Capex decision of the AER was based on an incorrect construction and application of the NER. In particular:

> *(a) the AER erred in construing cl 6.5.7(a)(2) of the NER as only giving rise to an altered standard of obligation by reference to whether specific legislative provisions had been amended. It failed to have regard to the objective content of such regulatory obligations at the relevant time. As a consequence, the AER failed to have proper regard to SA Power Network's actual regulatory obligations and requirements;*
>
> *(b) the AER erred in assessing the prudency and efficiency of the Bushfire Mitigation Capex Program by reference to whether a sufficient level of capex related expenditure had already been provided for 'business-as-usual bushfire risk management', in circumstances in which there was no specific business as usual bushfire risk management capex allowance; and*
>
> *(c) the AER erred in determining that cl 5.2.1(a) of the NER is not a regulatory obligation or requirement that imposes any augmentation capex obligation on a network service provider; specifically the AER erred in construing the provision as being limited to maintenance opex and as precluding capex designed to enhance the safety of the South Australian distribution network.*

319 As a consequence of this incorrect construction and application of the NER, SAPN contends that the AER exercised its discretion incorrectly and made a decision that was unreasonable, having regard to all the circumstances.

320 The AER is critical of SAPN's Amended Application for alleging numerous errors but failing to specify the category of error being alleged. It suggests the problem is compounded by SAPN's written submissions which are said not to be closely tied to the grounds of review in the Amended Application, making it difficult to discern whether the submissions are addressing grounds of review raised in the Amended Application, or raising new grounds of review.

321 The AER considers that the difficulties are exemplified by SAPN's overarching argument that the AER should have assessed whether the proposed Bushfire Mitigation Capex Program:

- was required to comply with a regulatory obligation or requirement for the purposes of cl 6.5.7(a)(2) of the NER; or
- alternatively, was required to maintain the safety of the distribution system for the purposes of cl 6.5.7(a)(4).

322 SAPN's contends that had the AER determined that the Bushfire Mitigation Capex Program met the capex objectives it was then required:

- to be satisfied that the Bushfire Mitigation Capex Program met the capex criteria and approve the program; or
- to substitute the cost sought by SAPN for the Bushfire Mitigation Capex Program with an alternative amount that the AER was satisfied would meet the capex criteria.

323 SAPN's maintains that the AER failed to clearly address these steps.

324 The AER's criticism of the way SAPN presented its case also extends to aspects of SAPN's written submissions which address matters of construction of the NER and legislation in South Australia.

325 The Tribunal does observe a change in emphasis between the Amended Application and SAPN's written submissions. This became more pronounced during oral argument where counsel for SAPN devoted a degree of attention – more than might first appear to have naturally emerged from the Amended Application – to several points of construction of the

NER and legislation in support of the view that the capex objectives had been satisfied, contrary to the view held by the AER.

326 Despite the AER's criticism of the "disconnect" between SAPN's Amended Application and its written submissions, it nevertheless responded to SAPN's arguments in its written submissions.

Compliance with a regulatory obligation or requirement under cl 6.5.7(a)(2) of the NER

327 SAPN argued that the correct approach is to first inquire whether the Bushfire Mitigation Capex Program is necessary in order to comply with a regulatory obligation or requirement under cl 6.5.7(a)(2), as part of the capex objectives.

328 The expression "regulatory obligation or requirement" as used in the capex objectives, is defined in s 2D of the NEL, and includes:

- a distribution system safety duty in relation to the provision of an electricity network service by a regulated network service provider; and
- an obligation or requirement under the NEL or the NER.

329 The expression "distribution system safety duty" is defined in s 2(1) of the NEL as follows:

> *distribution system safety duty means a duty or requirement under an Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act, relating to–*
>
> *(a) the safe distribution of electricity in that jurisdiction; or*
>
> *(b) the safe operation of a distribution system in that jurisdiction*

330 The expression "participating jurisdiction" is defined in s 5 of the NEL relevantly as follows:

> *(1) The following jurisdictions are participating jurisdictions for the purposes of this Law–*
>
> *(a) the State of South Australia; and*
>
> *(b) the Commonwealth, a Territory or a State (other than South Australia) if there is in force, as part of the law of that jurisdiction, a law that corresponds to Part 2 of the National Electricity (South Australia) Act 1996 of South Australia.*

331 SAPN points to three regulatory obligations it considers trigger cl 6.5.7(a)(2), through the combined operation of these definitions. They are (collectively the '**Obligations**'):

- the obligation to take reasonable steps to ensure that infrastructure is safe and safely operated under s 60(1)(b) of the Electricity Act;

- the obligation to ensure, as far as reasonably practicable, that the health and safety of workers and other persons is not put at risk: ss 5, 18 and 19 of the WHS Act; and
- the obligation to maintain and operate all equipment that is part of their facilities in accordance with good electricity practice and Australian Standards, within the meaning of cl 5.2.1(a) and Ch 10 of the NER.

332 Section 60(1)(b) of the Electricity Act provides:

> *(1) A person who owns or operates electricity infrastructure or an electrical installation must take reasonable steps to ensure that–*
>
> *(a) the infrastructure or installation complies with, and is operated in accordance with, technical and safety requirements imposed under the regulations; and*
>
> *(b) the infrastructure or installation is safe and safely operated.*

333 Section 19(1) of the WHS Act provides:

> *(1) A person conducting a business or undertaking must ensure, so far as is reasonably practicable, the health and safety of–*
>
> *(a) workers engaged, or caused to be engaged by the person; and*
>
> *(b) workers whose activities in carrying out work are influenced or directed by the person,*
>
> *while the workers are at work in the business or undertaking.*

334 Section 18 of the WHS Act defines "reasonably practicable" as follows:

> *reasonably practicable, in relation to a duty to ensure health and safety, means that which is, or was at a particular time, reasonably able to be done in relation to ensuring health and safety, taking into account and weighing up all relevant matters including–*
>
> *(a) the likelihood of the hazard or the risk concerned occurring; and*
>
> *(b) the degree of harm that might result from the hazard or the risk; and*
>
> *(c) what the person concerned knows, or ought reasonably to know, about–*
>
> *(i) the hazard or the risk; and*
>
> *(ii) ways of eliminating or minimising the risk; and*
>
> *(d) the availability and suitability of ways to eliminate or minimise the risk; and*
>
> *(e) after assessing the extent of the risk and the available ways of eliminating or minimising the risk, the cost associated with available ways of eliminating or minimising the risk, including whether the cost is grossly disproportionate to the risk.*

335 Clause 5.2.1(a) of the NER requires that:

> *(a) All Registered Participants must maintain and operate (or ensure their authorised representatives maintain and operate) all equipment that is part of their facilities in accordance with:*
>
> *(1) relevant laws;*
>
> *(2) the requirements of the Rules; and*
>
> *(3) good electricity industry practice and relevant Australian Standards.*

336 The expression "good electricity industry practice" is defined, in Ch 10 of the NER, as:

> *The exercise of that degree of skill, diligence, prudence and foresight that reasonably would be expected from a significant proportion of operators of facilities forming part of the power system for the generation, transmission or supply of electricity under conditions comparable to those applicable to the relevant facility consistent with applicable regulatory instruments, reliability, safety and environmental protection. The determination of comparable conditions is to take into account factors such as the relative size, duty, age and technological status of the relevant facility and the applicable regulatory instruments.*

337 SAPN submits that these provisions are indeterminate in scope and therefore describe categories of indeterminate reference which may be satisfied by conduct of various kinds. That is, they do not narrowly prescribe a series of specific actions that SAPN must take.

338 The AER agreed with this characterisation and was therefore surprised that SAPN appeared to be suggesting in its written submissions that its Bushfire Mitigation Capex Program was of determinative scope and therefore within its terms, a regulatory obligation or requirement.

339 If that indeed was the position held by SAPN, it had moved on by the time of the hearing. Counsel for SAPN said (at Transcript, pp 186-7):

> *Can I turn then to the first issue for consideration, which is whether the Bushfire Mitigation Program was required to be undertaken in order to comply with a regulatory obligation or requirement. Can I interpolate and note that in our submissions at 425 and 452, we use a shorthand for this notion.* ***SAPN, of course, doesn't contend that the bushfire program is itself a regulatory obligation. It contends that effecting it is necessary to fulfil an obligation.*** *As the tribunal is aware by clause 6.5.7(a)(2) of the rules, compliance with all applicable regulatory obligations or requirements that are associated with standard control services is one of the capex objectives. Standard control services are, through the combined operation of chapter 10 of the rules and section 2B of the law, services regulated under a distribution determination.*
>
> ***SAPN contends that three distinct but overlapping regulatory obligations require it to undertake the program.*** *They are the obligation to take reasonable steps to ensure that infrastructure is safe and safely operated under section 60 of the Electricity Act, the obligation to ensure, as far as is reasonably practicable, that the health and safety of workers and other persons is not put at risk. That's section 5, 18*

and 19 of the Work Health and Safety Act. And, finally, the obligation to maintain and operate all equipment that's part of their facilities in accordance with good electricity industry practice and Australian standards within the meaning of clause 5.2.1(a) and chapter 10 of the rules. It will, of course, suffice if but one of these obligations is a regulatory obligation requirement within the meaning of the capex objectives, and the tribunal concludes that the steps contemplated by the program are necessary are apt to achieve compliance with that obligation. However, SAPN submits that they are overlapping and they are complimentary sources of regulatory obligation.

(Emphasis added).

340 Further, in response to the Tribunal' s question whether there was only one means of compliance with the Obligations, counsel for SAPN replied (at Transcript, p 188):

Absolutely not. I agree with that and I'm about to come to that point. These are quintessentially categories of indeterminate reference. These obligations. ***It's not suggested that there was only means to comply with them.*** *What is suggested, for reasons I've indicated already and will return to, is that when you look at the very modest aspects of this program now pressed – when you look at key findings of the VBRC, the PBST and the Jacobs report – these are straightforwardly linked to fire. They are aspects, in respect of which SAPN is lagging behind good electricity industry practice. And they are standard issue, utterly non-gold plated pieces of infrastructure that will actually be used to supply that defect.*

(Emphasis added).

341 Counsel for the AER expressed surprise at that response (Transcript, pp 212-13):

And the question was to the effect was there only one method of compliance with the safety obligations. And I had understood my learned friend to answer that to say it's not being suggested that there's only one manner of compliance. That presents a difficulty, it seems to me, for the argument – I must say even replying to the argument presents a difficulty – because we had been proceeding on a certain understanding of the argument and the error. And, certainly, the biggest error being this is mandatory. That was the matter put to the AER and the tribunal will see in the reasons why that matter was addressed by the AER because of the way it was put. But there is a little bit of uncertainty there but I just flag that at the beginning.

342 To complete this dialogue, counsel for SAPN responded (Transcript, pp 242-3):

My learned friend suggested that I had made a concession that were many ways of complying with an obligation, and this was not the only way. My submission was, and it is SAPNs position that, the obligations in question are obviously indeterminate in content. There may be multiple ways of complying with them. The Jacobs report identified multiple proposed steps to comply with those obligations. What we contend is that what is now before the tribunal is the bare minimum necessary to comply with the obligations imposed by section 60, section 19 and clause 5.2.1(a), and it's important to recall that those obligations in that order have cascading levels of specificity. Section 60 is very broad. Section 19 is slightly narrower. 5.2.1(a), in speaking of good electricity industry practice, is directly addressing the kind of topic that is before the tribunal.

343 The Tribunal has taken some time over this dialogue because it goes to the heart of the approach in construing cl 6.5.7(a) and cl 6.5.7(c). It also again highlights some of AER's concerns in responding to SAPN's submissions, given its original pleading.

344 It is uncontroversial that forecast capex must comply with both the capex objectives and capex criteria. Here the focus of attention on the capex objectives is whether the Bushfire Mitigation Capex Program is required to comply with a regulatory obligation or requirement or in the alternative is required to maintain the safety of the distribution system.

345 In the passage reproduced above, counsel for SAPN suggests that what is now before the Tribunal (which we take to mean the capex sought as part of the Bushfire Mitigation Capex Program) is the minimum required to comply with the Obligations. Of course at one level that is incorrect. There is nothing in the statutory provisions underpinning the Obligations that expressly mandate any specific actions or any specific level of expenditure. Counsel for SAPN all but acknowledged that. The expenditure proposed by SAPN is not required to comply with those statutory obligations, in the sense that those statutory provisions mandate them.

346 Rather as the other passages suggest, SAPN's real contention is that the three distinct but overlapping legislative obligations require it to undertake the expenditure. As already indicated those legislative obligations do not mandate any particular actions or any particular expenditure. As SAPN quite rightly noted, those statutory obligations describe categories of indeterminate reference, which may be satisfied by conduct of various kinds. Therefore it is unsurprising that counsel for SAPN agreed (in the passage quoted) that there may be many means of discharging them. This is because they impose what may for convenience be referred to as reasonableness obligations.

347 At the heart of the issue then is the question of what should be the approach to the capex objectives where (as here) the regulatory obligation or requirement does not import specific obligations but rather reasonableness obligations which may be complied with in many ways.

348 In its submissions the AER contrasted two types of regulatory obligation. One type of regulatory obligation may be highly specific: for example, a regulation may require specific assets to be deployed in the electricity network. In those circumstances, a DNSP will not have any choice as to the assets to be deployed. In those circumstances, the AER's task under cl 6.5.7(c) is more confined. It must still assess any proposed capex by reference to the

capex criteria, but the assessment would start from the position that the deployment of the assets is necessary and the assessment is confined to the efficient and realistic costs of deployment.

349 The second is an obligation stated as a general principle, where there may be various means of compliance with the obligation. The Obligations that SAPN relies on are said to be of that kind – they are, in substance, reasonableness obligations. A DNSP may choose or propose a particular means of complying with such an obligation. The task of the AER is to assess the DNSP's proposal in accordance with the capex criteria.

The nature of regulatory obligations

350 In order to address SAPN's arguments it is useful to make some observations on the approach to assessing different types of regulatory obligation under the capex objectives and capex criteria.

351 In the Tribunal's view it is first necessary to clearly identify the regulatory obligation or requirement associated with the provision of standard control service. There must be a real, direct and tangible connection – one that is not remote.

352 Secondly it is necessary to determine the character of the regulatory obligation or requirement to determine its scope, what it seeks to address and what it demands. There are likely to be at least three types of regulatory obligation, each having different characteristics, which the Tribunal discusses below.

353 Thirdly it is necessary to examine whether the proposed capex has a direct connection in responding to the regulatory obligation or requirement, having regard to its identified character, scope and requirements.

354 Finally it is necessary to assess whether the forecast capex satisfies the capex criteria in the discharge of the regulatory obligations or requirements, as those obligations or requirements have been characterised under the second and third steps.

355 In the Tribunal's view there are arguably at least three types of regulatory obligation or requirement to which this approach may be applied. The first is one that imposes an express and specific direction, such that there is only one means of compliance, with fixed and determined costs. A second type of regulatory obligation is one that imposes a specific obligation, but does not specify the means of compliance so that costs will vary with the

method of compliance employed. A third type is one that adopts a principled approach – specifying only overarching outcomes that must be achieved, leaving considerable discretion as to the approach adopted.

356 Even in the case of the first type of obligation, compliance with all the above steps must still be demonstrated. The express nature of the obligation does not of itself exempt it from consideration under the capex criteria. However in practice, satisfaction of the capex criteria is likely to follow relatively easily. This is because, for instance it would not be prudent to disregard an express regulatory obligation risking breach of that obligation with the consequences that may follow from that breach. Similar considerations apply to the assessment under the efficiency limb of the capex criteria.

357 For the most part the approach to the second and third types can be taken together. The Tribunal considers that the Obligations relied on by SAPN are of the third kind because the legislation underpinning them adopts a principled approach – broadly to take reasonable steps concerning safety.

358 The Tribunal is not suggesting it is necessary to classify obligations in this way. It employs that approach here merely as a convenient analytical framework against which to examine the competing arguments of the parties.

359 This third type of principled obligation raises some obvious difficulties in applying cl 6.5.7. First, if the regulatory obligation does not specify what specifically is to be done, then how does one determine that an action taken is directly attributable to the discharge of that obligation? Secondly, as there are many means of compliance, what factors ought to be considered in determining a suitable mix of measures that ensures compliance? That takes on some importance because different measures will invariably involve different costs. Third, what are the “model” measures and corresponding costs against which the capex criteria, particularly prudency and efficiency, are to be assessed when there is nothing expressly mandated?

360 It is correct, if unhelpful in practice, simply to suggest that the answer to these questions is to consider the capex objectives and capex criteria within their terms. Ultimately of course that is what must occur as it is necessary to comply with both. However it is difficult to arrive at an answer – at least at the outset of one’s consideration – by simply employing that approach. This is because principled regulation carries with it the difficulties to which we have alluded.

361 In the case of principled regulation there is invariably some overlap between the capex objectives and capex criteria. For instance, whether the capex objectives have been discharged raises considerations such as what steps have been taken by other DNSP's, what is generally accepted in the industry, what alternatives are available, what has occurred in other jurisdictions and the like. These questions also go to the issue of what is prudent and efficient under the capex criteria. There is some fluidity between the capex objectives on the one hand and the capex criteria on the other, even though they are separate features of cl 6.5.7 of the NER.

362 As counsel for the AER said, the test for determining whether the capex objectives have been satisfied have components of prudency and efficiency built into them, even though those expressions expressly appear only under the capex criteria (Transcript, p 231):

> *On page 82, in the second full paragraph down there's a reference to the AER assessing the applicant's revised Bushfire Mitigation Program in two steps: (1), we assessed SA Power Network's compliance with its safety related obligations and its ability to manage bushfire risk. And (2), we assessed the prudency and efficiency of the three projects.*
>
> *It's tempting to put a label on paragraphs 1 and 2, labelling paragraph 1, 6.5.7(a) decision, the regulatory obligation decision, and labelling 6.5.7(c) the capex criteria decision. And plainly those two points do go to some extent can be divided in that way. The point I wanted to emphasise to the tribunal and the tribunal said, as it plays out in the reasons, one can't completely divorce those two steps, and I don't want to completely divorce those two steps. And one of the critical reasons one can't separate the two steps is the regulatory obligations that we're dealing with all have notions of reasonableness and prudence built into them.*
>
> *So that when the AER comes to consider in what way or to what extent is this asset replacement program required – is a regulatory obligation or required, it's looking at a question of prudency and reasonableness. If one is applying the same question under the capex criteria, one is applying the same sort of questions.* ***That's not to say there aren't still two questions, but it is to say that some of the considerations that will take into account in dealing with each aspect are very similar because of the nature of the regulatory obligations that you're dealing with.*** *So there can be questions does this point, which we will come to in a moment, go to defining the regulatory obligation or does it go to the capex criteria? It may well go to both, and quite appropriately go to both.*
>
> (Emphasis added).

363 Although the capex objectives and the capex criteria involve two separate and distinct considerations, the Tribunal agrees with the AER that in the case at least of principled regulation (under consideration here) it is not possible in practice to completely separate those two steps for the reasons mentioned above. More precisely, some of the features underpinning the capex criteria, particularly prudency and efficiency, may also be relevant in

determining whether the capex objectives have been discharged because they emerge naturally in considering principled obligations.

364 It is with these observations that the Tribunal now turns to consider SAPN's primary challenge.

365 As indicated, it is undisputed that the AER approached the task in two steps. It first assessed SAPN's compliance with its safety related obligations, and its ability to manage bushfire risk. Secondly it assessed the prudency and efficiency of the Bushfire Mitigation Capex Program.

366 As indicated, SAPN argued that that AER should have assessed whether the proposed Bushfire Mitigation Capex Program was required to comply with a regulatory obligation or requirement or alternatively, was required to maintain the safety of the distribution system. Having done that, SAPN argues that the AER was then required to be satisfied that the Bushfire Mitigation Capex Program met the capex criteria.

367 Implicit in SAPN's submission is that the AER has failed to assess whether the proposed Bushfire Mitigation Capex Program was required to comply with a regulatory obligation or requirement. That the AER's assessment of SAPN's compliance with its safety related obligations, and its ability to manage bushfire risk is not a substitute for undertaking this assessment which is required by cl 6.5.7(a)(2).

368 The Tribunal agrees with SAPN that the AER is required by cl 6.5.7(a) to assess whether the proposed capex is required to comply with a regulatory obligation or requirement. However it rejects SAPN's argument that the AER failed to do this.

369 In the AER's summary of its findings and conclusions on capex (Final Decision, Attachment 6, Table 6.2) there are a number of references to compliance with regulatory obligations and the capex criteria, including prudency and efficiency. Immediately following this summary the AER said (Final Decision, Attachment 6, pp 6-11):

> *We consider that overall our capex forecast addresses the revenue and pricing principles. In particular, we consider our overall capex forecast provides SA Power Networks a reasonable opportunity to recover at least the efficient costs it incurs in:*
>
> - *providing direct control network services, and*
> - *complying with **its regulatory obligations and requirements**.*
>
> *As set out in appendix B we are satisfied that our overall capex forecast is consistent with the NEO. We consider our decision promotes efficient investment in, and efficient operation and use of, electricity services for the long term interests of*

consumers of electricity.

We also consider that overall our capex forecast addresses the capital expenditure objectives. In making our final decision, we specifically considered the impact our decision will have on the safety and reliability of SA Power Networks' network. We consider this capex forecast should be sufficient for a prudent and efficient service provider in SA Power Networks' circumstances to be able to maintain the safety, service quality, security and reliability of its network consistent with its current obligations.

(Emphasis added).

370 Later, in describing its approach, the AER also alludes to compliance with regulatory obligations or requirements, in addition to the capex criteria (Final Decision, Attachment 6, pp 12-13).

371 Specifically in considering the Bushfire Mitigation Capex Program the AER also said (Final Decision, Attachment 6, p 81):

We are not satisfied that the additional capex for the proposed bushfire mitigation program is efficient additional capex that a prudent operator would require to maintain the reliability and safety of the network, or to comply with ***regulatory obligations or requirements****.*

(Emphasis added).

372 The passage suggests the AER was aware of the need to ensure the proposed capex was necessary to comply with a regulatory obligation or requirement. In the summary which followed (at p 82) the AER referred to a number of obligations arising under the Electricity Act and the WHS Act. These provisions are considered in some detail by the AER in the pages which followed under the heading "SA Power Networks' regulatory obligations and requirements". Leaving aside SAPN's challenge to the AER's construction of these provisions (discussed later in these Reasons for Determination), these are relevantly the regulatory obligations contended by SAPN. The fact that they have been considered in this manner, suggests the AER was mindful of the need to assess compliance with a regulatory obligation or requirement.

373 It is true that some of the passages quoted by the Tribunal and others that appear in the Final Decision clearly show that the AER was very much focused on the safety related obligations as well as the tests of prudency and efficiency. That is, in many respects they appear to run together. To the extent that they do, the Tribunal is satisfied from having considered the context, they arise as a natural consequence of considering principled regulation of this type as explained in our earlier observations. Namely that the issues of prudency and efficiency

arise naturally from this type of regulation. In the Tribunals' view that does not demonstrate the errors contented by SAPN.

374 In reaching this view the Tribunal is also mindful of the following comments of a differently constituted Tribunal in *Application by EnergyAustralia and Others* [2009] ACompT 8 at [312(i)] ('***EnergyAustralia***'):

> *The Tribunal is mindful that in considering the reasons of the AER, it is important to recall that the reasons are there to inform and are not to be scrutinised in a over-zealous way seeking to discern error from the way in which the reasons are expressed: see eg Minister for Immigration and Ethnic Affairs v Wu Shan Liang (1996) 185 CLR 259, 272. It is all a matter of degree, as an obvious inadequacy of the reasons may amount in any given case to an error in the process of fact finding or the exercise of a discretion. The Tribunal refers to its comments in the Application by EnergyAustralia (2009) ACompT 7 at [16].*

375 The Final Decision is a substantial document intended to explain the AER's reasons to a wide audience comprising many different stakeholders. As the Tribunal indicated in *EnergyAustralia*, the Final Decision should not be approached in an overly rigid way.

Change in the nature of the regulatory obligations and requirements over time

376 A related challenge is that the AER was in error in construing cl 6.5.7(a)(2) of the NER in such a way that it is enlivened only where there is an express amendment to the regulatory obligations or requirements applicable to SAPN. That is, the AER failed to have regard to whether the objective content of the Obligations had changed, where there was no statutory amendment. Accordingly, SAPN asserts that the AER failed to properly identify the regulatory obligations and requirements that applied to SAPN and did not assess the Bushfire Mitigation Capex Program in accordance with the capex objectives.

377 In particular, SAPN argues that the AER was in error by determining that the content of the Obligations was not altered by, among other things:

- the findings of the Victorian Bushfire Royal Commission ('**VBRC**') and the Powerline Bushfire Safety Taskforce ('**PBST**') concerning the ignition risks associated with the operation of reclosers and ageing infrastructure assets in BFRAs and the steps which can and should be taken to minimise those ignition risks;
- "good electricity industry practice" as defined Chapter 10 of the NER; and
- improvements in knowledge and technology and authoritative expert opinion.

378 The AER disagrees that it approached its decision in that manner.

379 As indicated, the AER agrees with SAPN's submission that the Obligations are indeterminate in scope and may be satisfied by conduct of various kinds.

380 Both SAPN and the AER refer to the following passage in the Final Decision in support of their respective positions (Attachment 6, pp 83-4):

> *In the preliminary decision, we acknowledged SA Power Networks' initiatives to date in reviewing its current practices and procedures for bushfire risk management following the release of the recommendations of the VBRC and the strategies proposed by the PBST. However we noted that there had not been a change to its regulatory obligations and safety standards related to bushfire risk that would justify additional expenditure. We also noted that the evidence before us indicated that it was compliant with its existing obligations.*

381 For SAPN, the reference to there being no "change" in the relevant obligations and safety standards is evidence that the AER only considered whether there had been a change in the regulations, and not whether the content of those obligations had been influenced by other events. Conversely, the AER relies on this passage to suggest that SAPN has mischaracterised its approach – including because the AER's focus on there being no change to regulatory obligations was to direct attention to whether the additional expenditure was justified.

382 Consistent with the comments in *EnergyAustralia* above, the Tribunal does not approach this task by reading the Final Decision in an overly rigid way. It is also not prepared to determine this question merely by construing this single passage as if it were legislation. It is necessary to look at the Final Decision in its totality.

383 The substantive discussion of the Bushfire Mitigation Capex Program commences at paragraph B.5 of Attachment 6 of the Final Decision. Shortly into this paragraph the AER said (at pp 81-2):

> *We are not satisfied that the additional capex for the proposed bushfire mitigation program is efficient additional capex that a prudent operator would require to maintain the reliability and safety of the network, or to comply with regulatory obligations or requirements. As such, we do not accept SA Power Networks' capex proposal to spend $38.9 million on its bushfire mitigation program. We find that SA Power Networks' revised regulatory proposal, and our alternative estimate, already factor in a sufficient level of capex related to its business-as-usual bushfire risk management.*
>
> *As we noted in the preliminary decision, the evidence before us indicates that SA Power Networks is meeting its existing obligations, and historically, its bushfire risk management has been effective. The Office of the Technical Regulator has confirmed that SA Power Networks currently satisfies existing regulations and standards relating to managing bushfires.*

384 The reference in this passage to SAPN meeting “its existing obligations, and historically, its bushfire risk management has been effective” is suggestive of two messages. One, as SAPN contends, is that the AER did not consider how existing obligations may have changed as a result of changing circumstances, outside of any legislative change. However it is equally consistent with the AER’s view that the words import existing statutory obligations as well as what those obligations require in light of any changed circumstances or events.

385 In the summary of its decision the AER refers to the legislative provisions which underpin the Obligations and the practice of Victorian networks, among other things (Final Decision, Attachment 6, pp 82-3). The AER expressly acknowledged SAPN’s initiatives in reviewing its current practices for bushfire risk management, following the release of the recommendations of the VBRC and the strategies proposed by the PBST. In the Preliminary Decision the AER also considered a number of reports that bear on this topic and the actions taken in Victoria in response to the VBRC.

386 After presenting its summary in the Final Decision, the AER then referred to the Obligations and SAPN’s contention that the Obligations are informed by factors which include the findings of the VBRC and the PBST. Then in considering SAPN’s express legislative obligations the AER said (Final Decision, Attachment 6, p 86):

> *On the information before us, we do not consider that SA Power Network’ current bushfire mitigation practices or expenditures are inadequate to meet its obligations under Section 60(1) of the Electricity Act …*
>
> *Rather, the evidence before us indicates that SA Power Networks is meeting its existing regulatory and safety obligations.*
>
> *As we have noted, the Office of the Technical Regulator in South Australia has advised that SA Power Networks is meeting its current bushfire obligations.*

387 The reference to SAPN meeting its “existing” regulatory obligations must be viewed in the context that what was under consideration here was the regulatory obligations under the Electricity Act and other relevant obligations. Although resorted to by SAPN in support of its position, it can equally be viewed as a short form reference to the fact that SAPN’s obligations were being assessed in the timeframe in which the Final Decision was being made, not at another time. That is, currency in this context does not necessarily carry with it the criticism advanced by SAPN that the AER failed to consider how the character of that obligation may change over time.

388 The AER also separately considered the obligations under the WHS Act. In considering the WHS Act the AER said (Final Decision, Attachment 6, p 94):

> *We do not consider that SA Power Networks' current obligations under the WHS Act justify the additional expenditure sought through the bushfire mitigation program. …*
>
> *The Energy Users Association of Australia (EUAA) submitted that, to its knowledge, the WHS Act has not been amended recently and does not contain any new obligations in relation to SA Power Networks management of risk. We agree with the EUAA. On the information before us, we do not consider that SA Power Networks is currently unable to meet its obligations under the WHS Act or that its obligations have changed such that additional capex is required to meet them.*

389 This passage also contains the expression "current" – presumably carrying with it the same defect in construction advanced by SAPN.

390 Additionally, to the specific passages to which the Tribunal has referred, the AER also undertook an extensive analysis of the level of bushfire risks in South Australia, Victoria and in other parts of the country, concluding (Final Decision, Attachment 6, p 94):

> *As we noted above, the evidence before us indicates that SA Power Networks is meeting its obligations under the Electricity Act. SA Power Networks has explained that it has a comprehensive and mature Bushfire Risk Management System (BRMS). This system has been in place since the early 1980s after investigations into the impacts of the 1983 Ash Wednesday fires in South Australia, and has been progressively improved since.*
>
> *In this section, we explain that we do not consider SA Power Networks has provided sufficient evidence that demonstrates its fire start risk has increased.*

391 The AER compared for example the measures taken in Victoria following the VBRC and the conditions in South Australia to determine whether the same measures ought to be employed in South Australia. Much as it did in the Preliminary Decision, the AER examined a number of reports as part of its analysis. The AER also examined information on fire-starts and differences in network design. It did so with the stated aim of determining whether the Bushfire Mitigation Capex Program was consistent with good electricity industry practice under cl 5.2.1(a) of the NER but also with obligations flowing from the WHS Act.

392 The nature and extent of the analysis undertaken by the AER is significant, not just for the conclusions the AER draws from it (much of it challenged by SAPN) but also for what it reveals about the analysis which the AER considered it was required to undertake. In particular the degree of analysis undertaken on fire conditions in Victoria and South Australia flows directly from the need to assess whether measures taken in Victoria after the VBRC ought to be applied in South Australia. The AER addressed these issues despite the fact that

the Final Report of the VBRC was delivered many years earlier in 2010 (and the report of the PBST in 2011). It is suggestive that the AER considered it was required to assess not only whether there had been a regulatory change but also how other events, outside of regulatory changes (like the outcomes of the VBRC) should be approached in assessing SAPN's Bushfire Mitigation Capex Program. The fact that the AER took this approach lends a deal of credibility to the AER's view that it was mindful of the correct approach to construction of the Obligations.

393 Having considered the Final Decision as a whole and for the reasons given above, the Tribunal is satisfied that the AER did not disregard the full impact of other events and circumstances on SAPN's obligations.

The VBRC, the PBST and the Jacobs report

394 SAPN also considers the AER was in error in failing to consider whether the Obligations were altered by the findings of the VBRC and the PBST or alternatively gave insufficient weight to the evidence advanced by SAPN from the VBRC and PBST. This is part of SAPN's overall criticism of the AER's approach in determining whether the capex was required by a regulatory obligation or requirement.

395 The Tribunal has effectively addressed the first part of this criticism in its consideration of the overall construction point above. The numerous passages the Tribunal referred to in considering that point leaves no doubt that the AER considered the findings of the VBRC and PBST and dealt with them extensively. It is unnecessary to address them again. That part of SAPN's argument fails.

396 The second part of SAPN's criticism is that the AER gave insufficient weight to the findings of the VBRC and PBST.

397 Accompanying its proposal to the AER, SAPN provided a report prepared by Jacobs: Recommended Bushfire Risk Reduction Strategies for SA Power Networks, Final Report October 2014. Jacobs considered current research, the VBRC and PBST reports, as well as bushfire risk management initiatives undertaken by DNSPs in other Australian states.

398 Jacobs considered it prudent for SAPN to implement additional risk mitigation strategies for the following reasons (at p 33):

- *The VBRC found that the events of Black Saturday called for "material reduction in the risk of bushfire caused by the failure of electrical assets". A* *similar expectation is likely to apply within South Australia;*

- *The subsequent PLBSTF identified a range of initiatives to reduce the likelihood of powerlines starting bushfires. Some of these are applicable to the distribution network in South Australia and are likely to now be considered as good industry practice within Australia; and*
- *General community expectation is that bushfire starts from electricity network assets are preventable by the network owner. Litigation against network owners has arisen from numerous bushfire events in Victoria and Western Australia in recent years.*

399 Jacobs then provided a detailed strategy analysis, recommending a number of measures SAPN should implement and the costs attributable to them (see pp 34-7).

400 SAPN argues that the AER should have accepted the findings of these reports, as they strongly support a conclusion that the Bushfire Mitigation Capex Program is a regulatory obligation or requirement. Instead the AER sought to distinguish between the requirements of Victorian DNSPs and SAPN, by suggesting that the findings made by the VBRC and PBST in relation to Victoria are not directly applicable to South Australia, because of greater overall areas of bushfire risk in Victoria, differences in network construction, and the statutory ability of SAPN (not Victoria) to cut off power in high bushfire risk situations. In any event, SAPN argues that the evidence does not support the AER's position.

401 SAPN also suggests that its proposal for the replacement of reclosers is more targeted than that suggested by the PBST. Additionally the fact it has adopted a number of network construction approaches which minimise the ignition risks associated with the operation of a distribution system in a BFRA does not mean it should ignore the demonstrated risks associated with the use of manual reclosers, RAGs and CLAHs in HBFRAs.

402 SAPN is critical of a number of subsidiary points relied on by the AER for distinguishing between the position in Victoria and South Australia. SAPN's criticism that the AER did not give adequate weight to the findings of the VBRC and PBST, is addressed below, as part of the Tribunal's consideration of those subsidiary points. However before doing so it is important to make a few comments in response to SAPN's primary submission that these reports, particularly the Jacob's recommendations, should have been adopted by the AER, almost as a matter of course.

403 The VBRC was asked to inquire into and report on the causes and circumstances of the fires that burned in January-February 2009, the preparation and planning before the fires, all aspects of the response to the fires, measures taken in relation to utilities and any other

matters it considered appropriate. It made 67 recommendations for reform covering areas including emergency and incident management, planning and building, land and fuel management and – relevantly to this matter – eight recommendations applying to electricity caused fire.

404 As is the nature of a Royal Commission, its task is to inquire, report and make recommendations. Ultimately it is for government to decide whether to adopt those recommendations, to determine how they should be adopted and the timelines by which that should occur. The fact that a Royal Commission makes a recommendation does not of itself mean that it will be adopted. Of course, its recommendations also have no binding effect until they are implemented, usually through legislative measures. No greater weight can be placed on the recommendations of a Royal Commission. The Tribunal is aware that some of the recommendations of the VBRC have been implemented while others are ongoing.

405 The PBST was established to recommend to the Victorian Government how two electricity-related recommendations of the VBRC – recommendation 27 (progressive replacement of 22kV and SWER powerlines) and recommendation 32 (disabling or adjustment of powerline reclose functions) should be implemented.

406 In relation to recommendation 27, the PBST provided the following guidance (p 9):

> *Electricity distributors implement the 2009 Victorian Bushfires Royal Commission's recommendation 27 by:*
>
> *(a) installing new generation protection devices to instantaneously detect and turn off power at a fault on high fire risk days:*
>
> - *on SWER powerlines in the next five years (new generation SWER ACRs)*
> - *on 22kV powerlines in the next 10 years (rapid earth fault current limiters)*
>
> *(b) targeted replacement of SWER and 22kV powerlines with underground or insulated overhead cable, or conversion of SWER to multi-wire powerlines, in the next 10 years*
>
> *to the level of between $500 million and $3 billion, consistent with the package of measures selected by the Victorian Government. These should be implemented in the highest fire loss consequence areas first.*
>
> *Any new powerlines that are built in the areas targeted for powerline replacement should also be built with underground or insulated overhead cable.*

407 The PBST's recommendation provides for several means of compliance with implementation packages ranging in cost as indicated within the recommendation.

408 In relation to recommendation 32, the PBST recommended that Electricity distributors adjust the protection systems for 22kV and SWER powerlines based on the severity of the day and the fire loss consequence of the area, as further described in that recommendation. The PBST made other recommendations to support this proposal. The Victorian Government embarked on an implementation program in response to the PBST recommendations.

409 As indicated, the VBRC and PBST made several recommendations in relation to the issues experienced in Victoria. As important as those recommendations may be, they have no force of themselves. It was the decision of the Victorian Government to implement them in that State in response to the VBRC which it established. This is the context in which the recommendations came to have a life in Victoria. The Tribunal therefore rejects SAPN's suggestion that the AER ought to have adopted the findings and recommendations of the VBRC and PBST in the absence of them being given any express regulatory recognition in South Australia.

410 SAPN's criticism is that even if they did not apply as a matter of statutory force, the AER was obliged to consider their application in South Australia as bearing on the Obligations. However as the Tribunal has already noted, the AER did consider the VBRC and the PBST extensively in its Final Decision.

Distinguishing the findings in Victoria

411 The way in which the AER considered these reports is also challenged by SAPN. Specifically the AER's approach in distinguishing the findings in Victoria because of greater overall areas of bushfire risk in Victoria, differences in network construction, and the statutory ability of SAPN (not Victoria) to cut off power in high bushfire risk situations.

412 SAPN maintains that the AER wrongly focused upon a comparison of the overall area of bushfire risk throughout Victoria and South Australia, when the only relevant comparison should be between HBFRAs in South Australia and Victoria. That is because SAPN's Bushfire Mitigation Capex Program recommends installation of SCADA reclosers and surge arrestors specifically in HBFRAs within South Australia, where SAPN's distribution system operates. SAPN maintains that where the VBRC and PBST made recommendations relating to HBFRAs in Victoria, those recommendations properly inform bushfire assessment in HBFRAs in South Australia.

413 SAPN argues it is not necessary that the underlying bushfire conditions or the network infrastructure be identical for the recommendations properly to inform a bushfire mitigation program in South Australia. The AER's conclusion that overall there are more areas of high bushfire risk in Victoria than South Australia is said not to be on point.

414 It is undisputed that the AER examined closely the difference in bushfire risk levels in Victoria and South Australia and the differences in network construction between Victoria and South Australia. Indeed it is that review of which SAPN is critical.

415 The AER asserts that the question whether certain recommendations made by the VBRC and the PBST should be considered to now constitute a mandatory safety obligation in South Australia, or whether they have now become good electricity industry practice, is a matter that is informed by a comparison of the geographic conditions, and consequential bushfire risk, as between the Victorian rural network areas and the rural parts of SAPN's network area.

416 The AER also maintains that local geographic and network conditions is relevant in considering any interregional translation of "reasonable steps" under the following definition of good electricity industry practice under the NER (Ch 10):

> *The exercise of that degree of skill, diligence, prudence and foresight that reasonably would be expected from a significant proportion of operators of facilities forming part of the power system for the generation, transmission or supply of electricity under conditions comparable to those applicable to the relevant facility consistent with applicable regulatory instruments, reliability, safety and environmental protection. The determination of comparable conditions is to take into account factors such as the relative size, duty, age and technological status of the relevant facility and the applicable regulatory instruments.*

417 It is said to be equally relevant to the application of s 60(1) of the Electricity Act and s 19 of the WHS Act.

418 In the Final Decision the AER examined in detail a number of matters including fire-start data and vegetation, fire intensity and fire risk maps in concluding that SAPN faced a lower bushfire risk than its Victorian counterparts. The AER maintains that a comparison of the fire risk areas reveal a clear difference of degree in vegetation density, fire intensity and bushfire risk between the South Australian HBFRAs and the highest-risk areas in Victoria. That comparison is said to be relevant to any assessment of whether the bushfire mitigation measures recommended in Victoria should be adopted in South Australia and the costs associated with their implementation in South Australia.

419 In the Tribunal's view it was open to the AER to consider the geographical, environmental and other differences in forming a view whether the recommendations of the VBRC applied in South Australia and how they might be applied. Once the automatic application in South Australia of the recommendations of the VBRC and PBST is rejected – as the Tribunal has indicated above ought to be the position – the issue of whether those measures constitute obligations or good electricity practice in South Australia must stand or fall on a full and proper consideration of the conditions and circumstances in South Australia compared to those in Victoria.

420 The Tribunal sees no objective reason why, in that circumstance, the AER ought to have excluded from its consideration geographical, environmental and other factors that bear on the bushfire risk levels in South Australia. Indeed a full and objective assessment required it to do so. Having embarked on that course, the AER undertook a comprehensive analysis spanning several pages of the Final Decision and drawing on several reports and published data. There can be no criticism that it gave insufficient attention to the factors which the Tribunal has indicated were open to it to consider. The Tribunal therefore rejects this plank of SAPN's challenge.

Additional matters supporting a regulatory obligation or requirement

421 SAPN also argues that the AER was in error in relying on three additional matters in support of its determination that the Obligations did not require SAPN to undertake the Bushfire Mitigation Capex Program. Those matters are:

- SAPN's ability to turn-off power supply to appropriately manage bushfire risks;
- the absence of an increase in fire danger caused by electrical assets due to forecast climactic conditions; and
- SAPN's historically improving fire-start performance.

422 All three matters also go to the heart of the issue whether the Bushfire Mitigation Capex Program satisfied the capex criteria. It is convenient to deal with the capex criteria later in these Reasons for Determination.

423 The first of these factors (the ability to turn off the power supply) was also relevant to the AER's consideration of the application of the VBRC and PBST in South Australia.

424 As the Tribunal has already indicated, it was open to the AER to consider all relevant factors in determining whether those reports applied on South Australia. The ability to turn off the power supply was one such factor. Accordingly there was no error in the AER having considered it. That is sufficient in itself to dispose of SAPN's criticism of AER's reliance on this factor. Nevertheless the Tribunal makes some brief comments on it below as SAPN's concerns extend also to the manner in which this issue was taken into account by the AER.

The ability to turn off the power supply

425 Section 53(1) of the Electricity Act provides the capacity to switch off supply in the following terms:

> *(1) An electricity entity may, without incurring any liability, cut off the supply of electricity to any region, area, land or place if it is, in the entity's opinion, necessary to do so to avert danger to person or property.*

426 Section 53(2) provides that if an electricity entity proposes to cut off a supply of electricity in order to avert danger of a bush fire, the entity should, if practicable, consult with the Chief Officer of the South Australian Country Fire Service before doing so.

427 The AER determined that as SAPN is empowered to cut off the power on extreme fire danger days, it does not necessarily follow that the frequency of asset-caused fires will increase correspondingly with the forecast increase in the frequency of extreme fire danger days.

428 SAPN rejects this determination for three reasons. First, the ability to turn-off power supply was considered in detail by the PBST, which noted that similar powers existed in Victoria. The fact that a similar power exists undermines any distinction that the AER sought to draw between SAPN and Victorian DNSPs. Secondly, the requirement for consultation in s 53(2) limits the speed within which this could occur. Thirdly, disconnecting the power can result in a large number of customers losing power for approximately 7 hours, places risk on people who rely on appliances for medical and other reasons and may undermine the reliability and security of the network in times of fire danger. These were factors also identified by the PBST.

429 SAPN relied on references made by the PBST to the Electricity Distribution Code in Victoria authorising power to be switched off. It is unclear, at least from that passage of the PBST, what is the source and scope of that power. In that same passage the PBST also referred to, but ultimately dismissed, comments made by the Chief Fire Office that it had the power to switch off supply.

430 In any case, the terms on which the power to switch off supply is cast is not the only basis on which the AER relied. It was also aware of the risks associated with switching off power which SAPN identified. It is clear that the AER turned its mind to some of the consequences associated with switching off supply and the measures in place by SAPN to manage these consequences (Final Decision, Attachment 6, p 97):

> *Regarding the additional risks to the community of turning off the power, we note that SA Power Networks has communicated to its customers that they should be prepared and have plans in place to cope with a power outage. It also advises the media and advertises regularly during the warmer months. We consider SA Power Networks has taken appropriate steps to ensure that community risks are minimised in the event of a power outage.*

431 The AER also noted advice from SAPN that it has an agreed set of criteria and procedures for using its power, which has been discussed with the Country Fire Service and the South Australian Government.

Increase in fire danger days

432 SAPN argues that the AER was in error by determining that evidence provided by SAPN did not support a conclusion that an increase in extreme fire danger days will lead to more fires caused by SAPN's electricity assets.

433 SAPN points to evidence to the effect that over 90% of fire-starts occur in the hottest five months of the year strongly suggests a correlation between hotter weather and an increased risk of fire-starts. Additionally SAPN relies on evidence from the Bureau of Meteorology ('**BoM**') and CSIRO suggesting that the number of extreme fire danger days per year had increased by 1.7 to 2.5 times since 2000, with that increase expected to continue. SAPN says that the increase in hotter weather, combined with the increased potential for fire-starts during hotter weather, creates a clear inference that SAPN's infrastructure will cause more fires in future.

434 Therefore SAPN maintains it will be required to take additional steps to comply with the Obligations and maintain the safety of the distribution system. Accordingly the AER was in error in not giving proper regard, or giving insufficient weight, to that evidence.

435 It should be noted that SAPN points only to a correlation between hotter weather and an increased risk of fire-starts. Its stops short of suggesting causality. Similarly SAPN suggests the potential for fire-starts during hotter weather merely creates an inference that SAPN infrastructure will cause more fires in future – there is no suggestion of a clear and direct

correlation. Having put its arguments no higher than that, relatively little would be required from the AER to rebut it.

436 The AER considered SAPN's arguments. It noted that the overall decrease in annual fire-starts occurred during a period when the number of fire danger days increased. The AER also pointed to the same data from the BoM of fire danger days referred to by SAPN. However the AER concluded that this evidence, in addition to evidence of SAPN's fire-start performance relative to Victorian distributors indicates that SAPN is managing its current fire-start risk appropriately (Final Decision, Attachment 6, p 98). The Tribunal rejects SAPN's assertion that the issue was not considered or given insufficient weight by the AER.

Fire-start performance

437 SAPN contends that the AER was in error by determining that SAPN's historical fire-start performance was relevant in assessing whether the Bushfire Mitigation Capex Program met the capex objectives and the capex criteria.

438 SAPN submits that the requirement to maintain the safety of the distribution system, (particularly in the context of an increase in extreme fire danger days and fire-starts) requires continual improvement. It cannot be acceptable for SAPN to determine that its historical fire-start performance is good and therefore that it need not take further precautionary steps.

439 Further, if the Bushfire Mitigation Capex Program is a regulatory obligation or requirement, SAPN is required to undertake the Bushfire Mitigation Capex Program independently of any general change to SAPN's historical fire-start performance. In that circumstance, SAPN's historical fire-start performance has no bearing on whether the Bushfire Mitigation Capex Program should have been approved and the AER was in error by placing any weight on that issue.

440 The AER suggests that SAPN's contentions are internally circular – if SAPN's fire-start performance has been shown to be improving then the regulatory obligation should not oblige SAPN to undertake the proposed capex in the face of that improvement.

441 In the Tribunal's view, SAPN's contention goes to the central feature of its overall pleading, namely that the content of obligations change over time. To suggest that the requirement to maintain the safety of the distribution system requires continuous assessment embodies that central concept. As the Tribunal has already noted above, it is satisfied that the AER turned its mind to this central contention. SAPN has not demonstrated why that central contention

should be viewed any differently in relation to fire-start performance than any of the other factors the AER considered and why accordingly the Tribunal should reach a different conclusion.

442 Additionally SAPN's argument is that historical fire-start performance was relevant in assessing whether the Bushfire Mitigation Capex Program met both the capex objectives and the capex criteria. Even if SAPN were able to demonstrate that the Bushfire Mitigation Capex Program was a regulatory obligation or requirement that is not a complete answer to the inclusion of the proposed capex. The proposed capex must still satisfy the capex criteria. The requirement for "continual improvement" does not of itself discharge that requirement.

Construction of the Electricity Act and the NER

443 SAPN raised several arguments challenging the AER's interpretation of s 60(1)(b) of the Electricity Act and cl 5.2.1(a) of the NER.

Electricity Act

444 As noted above, s 60(1)(b) of the Electricity Act provides:

> *(1) A person who owns or operates electricity infrastructure or an electrical installation must take reasonable steps to ensure that–*
>
> > *(a) the infrastructure or installation complies with, and is operated in accordance with, technical and safety requirements imposed under the regulations; and*
> >
> > *(b) the infrastructure or installation is safe and safely operated.*

445 SAPN's challenge stems from the following passage in the Final Decision where the AER said (Final Decision, Attachment 6, p 85):

> *Section 60(1) of the Electricity Act is a general safety obligation, which we consider must be considered against the context of other, more specific provisions of the Electricity Act.*

446 SAPN's contention is that the AER wrongly applied principles of statutory construction to read down s 60(1)(b) by reference to the other specific provisions in the Electricity Act. That is, the provisions referred to by the AER relate to discrete aspects of bushfire safety and do not expressly address all of the matters which could fall within the broad scope of s 60(1)(b). Those other specific provisions deal with insurance, compliance with the Safety, Reliability, Maintenance and Technical Management Plan, the capacity to turn off power and vegetation management.

447 In its Final Decision, the AER expressly addressed the specific provisions in the Electricity Act noted above (see Attachment 6, pp 85-6). It also relied on advice it received from the Office of the Technical Regulator (‘**OTR**’), discussed below.

448 This consideration arose at that point in the Final Decision where the AER had noted SAPN’s submissions in relation to its regulatory obligations, including the submission that s 60 imports broad objective standards of safety (see Attachment 6, p 84). The AER was therefore aware of SAPN’s construction. Shortly after that – in the context of assessing whether the capex was required by a regulatory obligation – the AER turned to consider the specific Electricity Act provisions. It is hardly surprising that it would do so because those provisions impose specific, identifiable obligations for example relating to insurance and licensing. The AER needed to assess whether those specific obligations were being discharged.

449 Having considered the relevant parts of the Final Decision noted, the Tribunal concludes that the AER did not read down the general obligations imposed by s 60 of the Electricity Act as SAPN contends. The Tribunal is satisfied that the AER gave s 60 of the Electricity Act its full effect in its consideration of whether the proposed capex was required to satisfy a regulatory obligation.

450 Finally, SAPN asserts that the AER erred by placing reliance on a discussion with an OTR representative as a valid means of determining the content of SAPN’s obligations under the Electricity Act.

451 The Final Decision notes advice from the OTR confirming that SAPN currently satisfies existing regulations and standards relating to managing bushfires. The AER then concludes (Final Decision, Attachment 6, p 86):

> *As we have noted, the Office of the Technical Regulator in South Australia has advised that SA Power Networks is meeting its current bushfire obligations. It is open for the technical regulator to review the material provided by SA Power Networks and their consultant Jacobs and determine whether formal changes to South Australian requirements are necessary. We would consider expenditure required to meet any new obligations either as part of the next reset process or as part of a cost pass through application from SA Power Networks.*

452 This conclusion follows several occasions in the Final Report where the AER relies on its own assessment in determining the content of SAPN’s obligations. The Tribunal does not discern any suggestion that the AER effectively delegated the task of assessing the content of SAPN’s Electricity Act obligations to the OTR. It is certainly the case (as the above passage shows) that the AER consulted with and took into account advice provided by the OTR.

SAPN has not raised any argument as to why it would be improper for the AER to do so, any more than it would be for the AER to receive input from any other person in making its decision.

Clause 5.2.1(a) of the NER

453 SAPN contends that the AER was in error by construing cl 5.2.1(a) of the NER as not imposing any augex obligation on SAPN and in construing the obligation as being limited to maintenance opex and repex programs only. As noted, the provision provides:

> *(a) All Registered Participants must maintain and operate (or ensure their authorised representatives maintain and operate) all equipment that is part of their facilities in accordance with:*
>
> *(1) relevant laws;*
>
> *(2) the requirements of the Rules; and*
>
> *(3) good electricity industry practice and relevant Australian Standards.*

454 SAPN's criticism is that the AER has placed too restrictive an interpretation on the phrase "maintain and operate" in this provision.

455 The following passage in the Final Decision highlights the approach taken by the AER (Attachment 6, pp 86-7):

> *We do not accept that the clause 5.2.1(a) good electricity industry practice obligation is a regulatory obligation or requirement that imposes any augmentation capex obligation on a network operator. Clause 5.2.1(a) relevantly requires that …*
>
> *That obligation specifies the standard to which a network operator must maintain and operate the equipment that is part of its distribution network facilities. It does not impose any obligation on a network operator to augment its existing facilities: at most, cl 5.2.1(a) might be seen to impliedly require a network operator to replace its existing equipment in the event that the equipment can no longer be maintained in accordance with good electricity industry practice or applicable standards.*

456 It will be noted that in the above passage the AER considered that the obligation under cl 5.2.1(a) does not extend to augmentation of the network. SAPN's criticism is that the phrase "maintain and operate", naturally extends to replacing out-dated infrastructure with more modern infrastructure over time. This reading is said to be supported by the use of the word maintain in conjunction with "good electricity industry practice". SAPN maintains that the definition expressly refers to a need for foresight in the operation of facilities, in the context of their technological status. It also requires SAPN to consider what would be expected following the findings of the VBRC and the PBST that relate to bushfire safety.

457 It is unnecessary for the Tribunal to determine the construction issue raised by SAPN. As indicated above, the Tribunal is satisfied that the AER did not apply a “static” concept of safety and also adequately considered the findings of the VBRC and PBST, in regards to their application in South Australia.

Maintaining the safety of the distribution system under cl 6.5.7(a)(4) of the NER

458 If the Bushfire Mitigation Capex Program was not required to comply with a regulatory obligation or requirement, SAPN’s alternative contention is that it is required to maintain the safety of the distribution system under cl 6.5.7(a)(4) of the NER.

459 SAPN says that the objective of maintaining safety is a separate and distinct obligation to a regulatory obligation and should be considered in light of several matters, including AEMC’s Rule Determination: National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013 (‘**2013 Rule Determination**’) at (ii) and 19. SAPN’s position is that whilst the AEMC considers matters of reliability and security of supply should be limited by relevant regulatory obligations and requirements, safety should not. The Tribunal does not accept that construction.

460 The AEMC’s determination arose in the context of an apparent lack of clarity in how the NER applied to a regulatory obligation relating for example to safety, compared with a safety obligation arising under objectives 3 and 4. The AEMC said in its 2013 Rule Determination (at p 10):

> *The Commission considers that, under the previous rules, it was not clear how the existing expenditure objectives worked together. This was because expenditure objective 2 required an NSP, in developing its regulatory proposal, to base its expenditure on complying with regulatory obligations or requirements for reliability, security, quality and safety. On the other hand expenditure objectives 3 and 4 could be interpreted such that they required this expenditure to be based on maintaining existing levels of reliability, security, quality and safety. This created a lack of clarity for the NSP when putting together its regulatory proposal and for the AER in determining an NSP’s expenditure allowance in relation to these measures.*
>
> *In addition, the previous expenditure objectives could have been interpreted to require the expenditure in an NSP’s regulatory proposal to be based on maintaining existing levels of reliability, security quality or safety, even where:*
>
> - *an NSP was performing above the required standards for these measures, or where*
> - *the required standards for these measures were lowered.*
>
> *The same issue arose when the AER determined the expenditure allowance.*

461 The AEMC then commented that in light of this problem, complying with standards in regulatory obligations or requirements is the appropriate objective for these measures. Nevertheless the AEMC did not consider it appropriate to amend the expenditure objectives for safety. This is because it considered that current levels of safety may appropriately have been influenced by safety standards in voluntary industry codes or Australian standards in addition to regulated standards. The AEMC's concern is that doing so could risk inadvertently reducing the level of safety delivered. Alternatively it could require those existing non-regulated standards to be moved to regulation to avoid any unintended reduction in safety levels (2013 Rule Determination, pp 10-11).

462 The AEMC said that where there are no regulatory obligations or requirements in relation to reliability, security, quality or safety then the issue of how the existing objectives work together does not arise. That is, in the absence of standards being set by the jurisdiction, the objective will be to maintain previous performance (2013 Rule Determination, p 11). The Tribunal does not understand the AEMC to be suggesting that expenditure on safety is in a sense "open ended".

463 SAPN also maintains that the safety obligation in cl 6.5.7(a)(4) is informed by the VBRC, the PBS and the Jacobs report. The obligation under cl 6.5.7(a)(4) is nonetheless an obligation relating to safety of the distribution system and in that sense has characteristics in common with the safety requirements said to arise under the Obligations.

464 The Tribunal has already traversed the submissions of SAPN in relation the VBRC, PBST and the Jacobs report in its consideration of the safety issues arising as a regulatory obligation or requirement. Therefore it is unnecessary to consider them again here. The Tribunal rejects SAPN's argument.

Compliance with the capex criteria

465 It is undisputed that the Bushfire Mitigation Capex Program must also satisfy the capex criteria.

466 SAPN contends that the AER was in error in concluding that the Bushfire Mitigation Capex Program did not satisfy the capex criteria. Specifically that the AER was in error in finding that:

(a) a sufficient level of capex related expenditure had already been provided for "business-as-usual bushfire risk management", when there was no specific or identifiable "business-as-usual bushfire risk management" capex allowance;

(b) SAPN was required to provide, but had not provided, a cost-benefit analysis in respect of the Bushfire Mitigation Capex Program; and

(c) the driver for the Bushfire Mitigation Capex Program was replacement based on age and condition (repex) that could be addressed using SAPN's repex allowance.

Business as usual bushfire risk management

467 SAPN's criticism is that the expression "business-as-usual bushfire risk management" is not found in the NEL, the NER, or the AER's guidelines. Further, the Final Decision did not specify or identify any "business-as-usual bushfire risk management" capex allowance.

468 It is uncontroversial that the expression "business-as-usual bushfire risk management" is not found in the NEL or the NER.

469 The expression "business-as-usual" appears in several places in the Final Decision. One such passage on which SAPN relies provides (Attachment 6, pp 81-2):

> *We are not satisfied that the additional capex for the proposed bushfire mitigation program is efficient additional capex that a prudent operator would require to maintain the reliability and safety of the network, or to comply with regulatory obligations or requirements. As such, we do not accept SA Power Networks' capex proposal to spend $38.9 million on its bushfire mitigation program. We find that SA Power Networks' revised regulatory proposal, and our alternative estimate, already factor in a sufficient level of capex related to its business-as-usual bushfire risk management.*

470 It is useful to look at the other parts of the Final Decision to gain a better understanding of what the AER intended to convey by that expression.

471 In addition to the passage noted above, the expression is used in several other places. For example, it emerges in the AER's consideration of historic fire-start performance. There the AER finds (Final Decision, Attachment 6, p 97):

> *Evidence provided by SA Power Networks shows that it has improved its fire-start performance to date using business-as-usual expenditure, and has done so during a period of increasing bushfire risk. The evidence further supports the view that SA Power Networks does not require additional expenditure to meet the capex criteria.*

472 The AER also used that expression in determining whether the business-as-usual approach to repex will provide SAPN with sufficient capex to manage the replacement of its assets and meet the capex objectives. Also in relation to the installation of modern surge arresters, the AER said that SAPN had been given additional business-as-usual repex that addresses increased asset replacement needs.

473 In its context, the Tribunal finds that the expression was used by the AER to refer to SAPN's existing asset replacement practices (particularly SCADA reclosers and surge arrestors) addressed by the repex forecast. Clearly the AER was using the expression as a shorthand reference to this and was not suggesting it is a requirement flowing from the NEL or NER.

474 Beyond this, SAPN also asserts that the AER did not specify or identify any "business-as-usual bushfire risk management" capex allowance. SAPN says it has not installed SCADA reclosers and surge arrestors at end of life using its repex budget. Only part of the cost of replacing manual reclosers with SCADA reclosers at end-of-life is funded through repex, namely that proportion of the cost equal to replacement with a modern equivalent. SAPN therefore argues it is an error to suggest that it could fund SCADA reclosers and surge arrestors through its repex allowance.

475 SAPN's concern is not simply whether the repex was adequate to fund SCADA reclosers and surge arresters. It is also that the AER was not mindful that the Obligations import changes in circumstances (including in relation to safety) and therefore the "business-as-usual" approach adopted by the AER is incapable of responding to that construction.

476 The Tribunal has already concluded that the AER was aware of and had regard to the fact that the Obligations may change over time. Once this is accepted, business-as-usual bushfire risk management must be viewed for the shorthand reference which we consider the AER intended it to convey. In that context, the AER appears to have proceeded on the basis that the business-as-usual approach would be sufficient for SAPN to meet its safety obligations (Final Decision, Attachment 6, p 77):

> *We are satisfied that the business as usual approach to repex will provide SA Power Networks with sufficient capex to manage the replacement of its assets and meet the capex objectives of maintaining safety, reliability and security of the distribution system. The business as usual approach takes into account the service provider's recent replacement practices, together with information on the age of its current stock of assets, to estimate the replacement volumes and expenditure the service provider business is likely to require if it maintains its current asset replacement practices over the next period. As noted in the Expenditure Forecast Assessment Guideline, we consider that its replacement practices in the last period were*

> *appropriate to allow the business to meet the capex objectives. We consider that adoption of the business as usual estimate approach means these asset replacement practices will continue to allow the businesses to meet the capex objectives.*

477 Although SAPN undoubtedly rejects the adequacy of the repex component of the total capex forecast, the AER reached a position of satisfaction having considered what was necessary to discharge SAPN's capex objectives, consistent with the prudency and efficiency requirements of the capex criteria. That involved the exercise of some judgement. The Tribunal is not satisfied that the SAPN has mounted any arguments to suggest this judgement was not open to the AER.

Cost-benefit analysis

478 SAPN contends that the AER was in error by determining that SAPN was required to provide, and had not provided, a cost-benefit analysis in respect of the Bushfire Mitigation Capex Program. It is undisputed that the SAPN did not provide a cost-benefit analysis, though it says it provided sufficient information to the AER to enable the AER to undertake a cost-benefit analysis. The implication is that if a cost-benefit analysis was indeed required, then the AER had before it information to undertake that analysis, but failed to do so.

479 SAPN refers to the AER's Explanatory Statement to the Expenditure Forecast Assessment Guideline. The Better Regulation Guidelines suggests a cost-benefit analysis is typically required by the AER to demonstrate that forecast expenditure meets the efficiency and prudency criteria in the NER. SAPN indicates that the Better Regulation Guidelines make clear that a cost-benefit analysis allows for a quantitative assessment of the overall monetary costs of programs against their overall monetary benefits to consumers, to determine which program provides the most net benefit.

480 SAPN's position is that such a cost-benefit analysis is inappropriate where the program relates to network safety. This is because the cost to be considered is in monetary terms and the benefit to be considered is not only economic, but includes the prevention of loss of life or serious injury. Monetary costs cannot be quantitatively compared with loss of life and serious injury, and that comparison necessarily requires a level of subjective or qualitative assessment. In such a circumstance SAPN says that a strict comparison of monetary costs and benefits contemplated by the Guideline is not possible and should not be required.

481 The Tribunal rejects that argument. It is common knowledge that courts are regularly called on to ascribe a monetary value to life and injury in the form of compensation for personal

injuries. As unfortunate as it may be, it is possible to place a monetary value on life and injury. In the context of this matter, the capex criteria in the NER do not draw any distinction between costs related to safety or other capex costs. This suggests that safety related costs must run exactly the same efficiency and prudency gauntlet as any other claimed capex. In that context the requirement for a cost-benefit analysis (such as that specified in the Better Regulation Guidelines) is apt.

482 A related submission of SAPN is that the AER ought not to have required SAPN to provide a cost-benefit analysis to demonstrate the "as low as reasonably practicable" risk mitigation principle. SAPN's reasons are similar to its objection to a cost-benefit analysis for the Bushfire Mitigation Capex Program in total – namely that qualitative not quantitative approaches should be applied to loss of life and injury. The Tribunal does not accept that argument for the same reasons given above.

483 Alternatively, SAPN submits that the AER had before it evidence that allowed it to make a qualitative assessment that the Bushfire Mitigation Capex Program was not grossly disproportionate to the benefit gained from the risk reduction, but failed to consider that evidence.

484 The AER maintains that the information SAPN provided did not endeavour to measure the relative costs and benefits of all available measures.

485 Even assuming the information SAPN provided the AER was sufficient to undertake a cost-benefit analysis, SAPN has not identified any provision of the NER or NEL that obliges the AER to undertake such a task. It would be an unusual regulatory regime that entitles a DNSP to provide a "data dump" to the regulator with the expectation that the regulator undertake its own quantitative analysis, as it sees fit.

Augmentation versus replacement

486 SAPN argues that the AER was in error by determining that the driver for the Bushfire Mitigation Capex Program was replacement based on age and condition (repex), which could be addressed using SAPN's repex allowance.

487 As SAPN explained, the Bushfire Mitigation Capex Program did not propose replacement of assets with an "equivalent" device, nor did it propose to replace assets which had deteriorated or reached the end of their economic life. Rather SAPN had proposed expenditure on newer types of assets that it considered provided improved or safer functionality.

488 In dealing with this issue in the Final Decision, the AER relevantly said (Attachment 6, p 100):

> *In the sections above we have considered SA Power Networks' compliance with its regulatory obligations and its ability to manage the existing and potential risks. As explained, we consider that SA Power Networks' proposed additional expenditure does not reasonably reflect the capex criteria.*
>
> *However, as an additional step, we have also considered whether the three projects that form its revised bushfire mitigation program reasonably reflect the capex criteria at an individual project level. These proposed projects include SCADA reclosers, surge arrestors and metered mains. We consider these projects below. …*
>
> *We recognise that the installation of SCADA reclosers may mitigate fire start risks, however we consider the replacement of aging reclosers funded through augex does not reasonably reflect the capex criteria. We have provided funding for the replacement of aging reclosers in our repex allowance, and expect that SA Power Networks will prioritise its repex program in accordance with its risk management framework.*

489 Part of SAPN's objection emerges from the final paragraph of this passage and the classification employed there by the AER in dealing with SCADA reclosers. However that paragraph must be understood in the context of the two paragraphs which precede it. It is clear from the first paragraph that the AER had already considered and rejected the additional capex expenditure as not satisfying the capex criteria. The analysis which it then undertakes is what it describes as "an additional step".

490 The AER had not made the determination claimed by SAPN. As the full passage indicates, the AER took the approach of assessing whether the proposed expenditure met the capex criteria as required under the NER. As the Tribunal has already found there was no error in the AER's approach to the capex criteria, it is sufficient to dismiss SAPN's submissions on this point.

Conclusion

491 For the reasons given, the Tribunal concludes that the AER did not, in its decision concerning the Bushfire Mitigation Capex Program, make the errors of fact pleaded by SAPN, incorrectly exercise its discretion or make a decision that was unreasonable in all the circumstances. SAPN fails on this aspect of its application.

Forecast labour cost escalation

492 A component of the AER's decision concerning forecast opex under cl 6.5.6 and cl 6.12.1(4) of the NER is an annual escalator to take account of likely changes in prices (input costs),

output and productivity during the regulatory control period. A similar approach is applied to forecast capex under cl 6.5.7 and cl 6.12.1(3) of the NER.

493 To forecast price growth, the AER uses a weighted average of forecast labour price growth and forecast non-labour price growth. The weighting applied by the AER in the Final Decision was 62% for labour and 38% for non-labour. The escalator used for forecasting non-labour price growth is CPI. This is undisputed. It is only the labour price component that is in dispute.

494 In its Regulatory Proposal, SAPN proposed that the AER should adopt real labour cost escalators of:

- +1.66% per annum for 2015-16 and 2016-17, based on the nominal wage increase outcomes negotiated by SAPN under its EA for 2014-16; and
- +1.77% per annum for 2017-18 through 2019-20, being the forecasts based on the Frontier Economics' Wage Price Index ('**WPI**') for Electricity, Gas, Water and Waste Services ('**EGWWS**') in South Australia.

495 SAPN indicated in its Revised Proposal that compliance with the EA is mandatory and the EA is a "regulatory obligation or requirement", as described in s 2D(b)(v) of the NEL.

496 In its Final Decision, the AER rejected SAPN's proposed increments, and substituted real labour cost escalators of:

- +0.50% and +0.45% for 2015-16 and 2016-17, respectively; and
- values increasing from +1.00% to +1.45% for the years 2017-18 through 2019-20 based on the average of the EGWWS WPI forecasts provided by Deloitte Access Economics and BIS Shrapnel.

497 It will be seen that the dispute relates only to the approach adopted by the AER in relation to the first two years of the regulatory control period.

498 SAPN submits that its EA is a "regulatory requirement or obligation" for the following reasons:

- the EA is an instrument made or issued under or for the purposes of the *Fair Work Act 2009* (Cth) ('**FW Act**'), which in turn is an Act of a participating jurisdiction (namely, the Commonwealth);

- section 50 of the FW Act requires SAPN to comply with its EA; and
- the EA materially affects the provision by SAPN of the electricity network services that are the subject of the Final Decision.

499 For SAPN, a consequence of this view is that:

- the costs incurred by it in complying with its EA are costs that meet the expenditure objectives in cl 6.5.6(a)(2) and cl 6.5.7(a)(2);
- SAPN's proposed labour cost escalators reasonably reflect the prudent and efficient cost of achieving the expenditure objectives; and
- the AER was required to take into account the principle that SAPN should be provided with a reasonable opportunity to recover at least the efficient cost of complying with the regulatory obligation created by or under the FW Act.

500 The AER did not accept that the EA is a regulatory obligation or requirement. In its Final Decision it said (Attachment 7, p 45):

> *We consider EA's are not a 'regulatory obligation or requirement' as defined in section 2D of the NEL.*
>
> *The fact that the EA requires certification under the Fair Work Act 2009 does not make it an instrument "made or issued by or under" that Act. Likewise, the fact that the Fair Work Act 2009 contains provisions regulating certain procedures by which an enterprise and its employees may make an EA does not mean that EAs are "made under" the Act. Section 182 specifies than an EA is made when a majority of employees vote to approve the agreement. It follows that an EA is made by agreement between the enterprise and its employees but regulated by an Act. The agreement made between parties is not made or issued under an Act.*

501 The AER also concluded that the EA is not an instrument that "materially affects the provision of electricity network services" under s 2D (Attachment 7, p 45):

> *We also note an EA is not an instrument that "materially affects the provision of electricity network services" within the meaning of section 2D. The EA itself has no effect on the provision of network services. There is no necessary connection between the terms of the EA and the nature, quality or quantity of network services supplied by a DNSP. An EA is not a requirement to provide electricity network services and a DNSP may arrange labour on many bases that do not involve an EA.*

Application of the NER

502 Clause 6.5.6(a) of the NER states the opex objectives in relation to DNSPs as follows:

> *(a) A building block proposal must include the total forecast operating expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of*

the following (the operating expenditure objectives):

(1) meet or manage the expected demand for standard control services over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services*;*

(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

(i) the quality, reliability or security of supply of standard control services; or

(ii) the reliability or security of the distribution system through the supply of standard control services,

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of standard control services; and

(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and

(4) maintain the safety of the distribution system through the supply of standard control services.

(Emphasis added).

503 Clause 6.5.7(a) of the NER is in similar terms, in its application to capex.

504 Clause 6.5.6(c) prescribes the opex criteria as follows (‘**opex criteria**’):

(c) The AER must accept the forecast of required operating expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflects each of the following (the operating expenditure criteria):

(1) the efficient costs of achieving the operating expenditure objectives; and

(2) the costs that a prudent operator would require to achieve the operating expenditure objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

505 Clause 6.5.7(c) of the NER is in the similar terms, in its application to capex.

506 Clause 6.5.6(d) provides that if the AER is not satisfied as referred to in cl 6.5.6(c), it must not accept the DNSP forecast.

Areas of Dispute

507 SAPN contends that the AER wrongly concluded that SAPN's EA was not a regulatory obligation or requirement. Alternatively, the AER wrongly concluded that the FW Act which requires SAPN to comply with its EA, was not a regulatory obligation or requirement applicable to SAPN.

508 SAPN's position is that had the AER correctly determined that compliance with SAPN's EA was a regulatory obligation or requirement, it would have followed that the escalation of SAPN's labour costs in the first two years of the 2015-20 regulatory control period, in accordance with the EA, would satisfy the expenditure criteria and therefore should have been accepted.

509 SAPN's contention is that the AER made an error of fact or facts that was material to the making of the decision, that the exercise of the AER discretion was incorrect and the decision unreasonable, having regard to all the circumstances.

510 In its written submissions, SAPN argues in the alternative that if the EA is not a regulatory obligation or requirement, it is required to achieve the opex and capex objectives, namely, the objective as articulated in cl 6.5.6(a)(4) and cl 6.5.7(a)(4) to "maintain the safety of the distribution system through the supply of standard control services". Also, the EA reasonably reflects the opex and capex criteria in cl 6.5.6(c)(3) and cl 6.5.7(c)(3) as realistic expectations of the demand forecast and costs inputs required to achieve the opex and capex objectives.

511 The AER objected to SAPN raising these alternative grounds, claiming they were not raised as a grounds of review in SAPN's Amended Application or in submissions before the AER as required under s 71O(2)(a) of the NEL. The AER maintained that objection during oral argument. The Tribunal indicated that ordinarily a fairly generous view is taken in cases where, as here, there is some reference to the grounds now advanced (albeit minimal), in submissions to the AER during the making of its decision. SAPN did not apply to amend its pleading and the AER proceeded to also address these grounds.

Regulatory obligation or requirement

512 The expression "regulatory obligation or requirement" is relevantly defined in s 2D(1)(b)(v) of the NEL as follows:

> *an Act of a participating jurisdiction, or any instrument made or issued under or for*

> *the purposes of that Act … that materially affects the provision, by a regulated network service provider, of electricity network services that are the subject of a distribution determination or transmission determination.*

513 As previously mentioned, a "participating jurisdiction" is a jurisdiction within the meaning of s 5(1) of the NEL, which relevantly provides:

> *(1) The following jurisdictions are participating jurisdictions for the purposes of this Law–*
>
> *(a) the State of South Australia; and*
>
> *(b) the Commonwealth, a Territory or a State (other than South Australia) if there is in force, as part of the law of that jurisdiction, a law that corresponds to Part 2 of the National Electricity (South Australia) Act 1996 of South Australia.*

514 SAPN submitted that the Commonwealth is a participating jurisdiction through the following interrelated definitions.

515 The *Australian Energy Market Act 2004* (Cth) ('**AEM Act**') is a law that is in force in the Commonwealth and corresponds with Pt 2 of the NESA Act, which provides for the operation of the NEL and NER. Section 6 of the AEM Act provides:

> *Application of National Electricity Law in offshore areas etc.*
>
> *(1) The National Electricity Law set out in the Schedule to the National Electricity (South Australia) Act 1996 of South Australia as in force from time to time:*
>
> *(a) applies as a law of the Commonwealth:*
>
> *(i) in the offshore area of each State and Territory; and*
>
> *(ii) in any other places, to any circumstances, or to any persons, that are prescribed by regulations for the purpose of this subparagraph; and*
>
> *(b) so applying may be referred to as the National Electricity (Commonwealth) Law.*
>
> *(2) The reference in subsection (1) to the National Electricity Law set out in the Schedule to the National Electricity (South Australia) Act 1996 of South Australia as in force from time to time includes a reference to any Rules or other instruments, as in force from time to time, made or having effect under that Law.*

516 The AER does not contest that the Commonwealth is a participating jurisdiction, albeit that s 6 of the AEM Act appears to have been enacted only to ensure the application of the NEL to Australia's offshore areas.

517 The second limb of the definition of "regulatory obligation or requirement" is whether the EA is an "instrument made or issued under or for the purposes of that Act", relevantly the FW Act. As noted the AER concluded that the EA is not made under the FW Act but is rather an agreement between the enterprise and its employees, though regulated by the FW Act. The agreement made between parties is not made or issued under an Act.

518 In *Toyota Motor Corporation Australia Ltd v Marmara* [2014] 222 FCR 152 ('***Toyota Motor***'), the Full Court of the Federal Court (Jessup, Tracey, and Perram JJ) made the following comments in relation to the character of an EA:

> *[88] We do not accept that premise, or the appropriateness of the contractual analogy. Under the FW Act, an enterprise agreement is an agreement in name only. …*
>
> *[89] … The effect of the legislation is to empower the employer and the relevant majority of its employees to specify terms which will apply to the employment of all employees in the area of work concerned. The legal efficacy of those terms will arise under statute, not contract, and, as mentioned above, will be felt also by those who did not agree to them. Someone, such as an employee subsequently taken on, who had nothing to do with the choice of the terms or the making of the agreement, will be exposed to penal consequences under s 50 if he or she should happen to contravene one of the terms. When viewed in this way, it is not difficult to share in the perception that an enterprise agreement approved under the FW Act has a legislative character.*

519 As the Full Federal Court has indicated, an EA is an agreement in name only. The legal efficacy of the terms under an EA arise under statute, not contract. The AER has not put forward any argument to distinguish SAPN's EA from the construction articulated by the Full Federal Court in *Toyota Motor*, which must therefore prevail. The second limb of the definition is therefore satisfied.

520 The third limb is whether the Act or instrument materially affects the provision of electricity network services.

521 In the Tribunal's view neither the FW Act nor the EA satisfies this third limb, for several reasons.

522 There must be a direct connection between the Act and instrument and the provision of electricity network services. The direct connection is the labour needed to provide those services, not the mechanism (in this case the EA) that is employed to deliver the labour. It would equally have been open to SAPN to engage labour through other means, for example a third party labour provider. Depending on the means chosen, the employment terms and conditions (and importantly the accompanying costs) would be different, but with no

corresponding impact on the provision of electricity network services. It would be an odd circumstance where the definition is attracted merely by the vehicle chosen to deliver that labour.

523 Additionally, the FW Act applies to all Australian companies. The EA model is open to companies across many industries, not just DNSPs. In that sense there is no unique connection between the EA and the provision of electricity network services, any more than there is to any other industry.

524 The other examples of regulatory obligation or requirement under s 2D also sheds some light on the type of matters contemplated. It is useful for this purpose to reproduce s 2D(1):

> *2D – Meaning of regulatory obligation or requirement*
>
> *(1) A regulatory obligation or requirement is–*
>
> *(a) in relation to the provision of an electricity network service by a regulated network service provider–*
>
> *(i) a distribution system safety duty or transmission system safety duty; or*
>
> *(ii) a distribution reliability standard or transmission reliability standard; or*
>
> *(iii) a distribution service standard or transmission service standard; or*
>
> *(b) an obligation or requirement under–*
>
> *(i) this Law or Rules; or*
>
> *(ia) the National Energy Retail Law or the National Energy Retail Rules; or*
>
> *(ii) an Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act, that levies or imposes a tax or other levy that is payable by a regulated network service provider; or*
>
> *(iii) an Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act, that regulates the use of land in a participating jurisdiction by a regulated network service provider; or*
>
> *(iv) an Act of a participating jurisdiction or any instrument made or issued under or for the purposes of that Act that relates to the protection of the environment; or*
>
> *(v) an Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act (other than national electricity legislation or an Act of a participating jurisdiction or an Act or instrument referred to*

> *in subparagraphs (ii) to (iv)), that materially affects the provision, by a regulated network service provider, of electricity network services that are the subject of a distribution determination or transmission determination.*

525 It can be seen that subss 2D(1)(b)(ii)-(iv) deal with instruments which impose levies or taxes or apply to the use of land or the protection of the environment. They are in the nature of instruments which the legislature has prescribed. In contrast the EA (although having a statutory character once implemented as described by the Full Federal Court in *Toyota Motor* Corporation) is nevertheless within the choice of SAPN management. The decision to pursue an EA was not "imposed" on SAPN by s 2D in the same way that taxes and levies for example are imposed on it under s 2D.

526 The NEO provides:

> *The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to–*
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
>
> *(b) the reliability, safety and security of the national electricity system.*

527 The NEO indicates that the overarching objective is to ensure the efficient investment in and operation of electricity services for the long-term interests of end users. The NEO is supported, among other things, by the opex criteria which directs attention to whether opex costs are prudent and efficient. The contents of an EA (at least at the point of its establishment) is something which is negotiated by SAPN management and the employees covered by the EA. Despite the best efforts of a DNSP (like SAPN), there is the capacity for an EA to include terms (and corresponding costs) that are not conducive to meeting the NEO, for example because a DNSP needs to accede to employee demands. Ultimately an EA is the product of negotiation and there is considerable discretion on SAPN on the costs associated with complying with the terms of an EA. It is not necessarily benchmarked to provide the necessary comfort that EA costs are efficient. The Tribunal does not accept SAPN's submission that the arms-length negotiation of its EA is a substitute for benchmarking or other appropriate means for testing its costs.

528 SAPN suggested that its EA is comparable to the EA considered by a separately constituted Tribunal in *Ausgrid*. There at [416]-[417] the Tribunal was faced with the AER's conclusion that the EA was not a regulatory obligation or requirement because it was not made under the

law of a participating jurisdiction (namely the Commonwealth). The Tribunal there was asked to consider whether the Minister's intervention amounted to a concession that the Commonwealth was a participating jurisdiction (at [418]). As the Tribunal made very clear, it was not necessary for it to delve further into that question. The Tribunal did not decide that an EA was a regulatory obligation or requirement.

529 For these reasons the Tribunal concluded that the FW Act and the EA made under that Act is not a regulatory obligation or requirement associated with the provision of standard control services.

Maintaining the safety of the distribution system

530 SAPN's alternative argument is that even if its EA is not a regulatory obligation or requirement, it is still necessary to maintain the safety of the distribution system, and falls within the opex and capex objectives in cl 6.5.6(a)(4) and cl 6.5.7(a)(4) of the NER.

531 Clause 6.5.6(a)(4) and cl 6.5.7(a)(4) direct attention relevantly to whether the EA is necessary to "maintain the safety of the distribution system through the supply of standard control services".

532 SAPN again argues that *Ausgrid* accepted that labour costs derived in accordance with an EA reasonably reflects the opex and capex criteria mentioned. One of the passages from *Ausgrid* relied on by SAPN in support of this view is the following at [418]:

> *Noting that in its Final Decisions the AER maintained the view that the Commonwealth is not a "participating jurisdiction", Networks NSW draws on the Minister's intervention in these proceedings to submit that the AER now acknowledges that status. It is, however, unnecessary to delve further into whether the Minister's intervention amounts to a concession on the part of the AER.* ***That is because the EBAs may be reasonably regarded as:***
>
> **(a)** ***otherwise required to achieve an opex objective, namely, the r 6.5.6(a)(4) objective to: "maintain the safety of the distribution system through the supply of standard control services"; and***
>
> **(b)** ***reasonably reflecting the opex criteria in r 6.5.6(c)(3): "a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives."***
>
> (Emphasis added).

533 SAPN points in particular to the highlighted passage for the proposition that *Ausgrid* decided that labour costs derived in accordance with an EA reasonably reflects the opex and capex criteria. As explained above, the Tribunal there found it unnecessary to decide whether an

EA was a regulatory obligation. It is then that the highlighted passage appears where the Tribunal indicates that "the EBAs may be reasonably regarded as … [required to achieve the opex objective and opex criteria]". That conclusion is reached from the following passage in which the Tribunal quotes from the AER's reasons, at [419]:

> *That the EBAs may be so regarded may be seen in the following paragraphs (without footnotes) from Attachment 7 to the Ausgrid Final Decision (at p 7-86) in which the AER, while rejecting the EBAs as a 6.5.6(a)(2) "regulatory obligation or requirement', recognised that the EBAs may affect the Networks NSW DNSPs' provision of standard control services:*
>
> > *We also disagree with the service providers' submissions that compliance with the terms of their own EBAs is a 'regulatory obligation or requirement'. For example, service providers have referred to redundancy costs 'required to be paid as a regulatory obligation'.*
> >
> > *… of the six possible (and exhaustive) categories of obligations or requirements … , EBAs could conceivably only fall with an Act or instrument made or issued that 'materially affects a service provider's provision of electricity network services'. This is because the terms of an EBA could plausibly materially affect a service provider's provision of standard control services. However, that Act or instrument must be made by a 'participating jurisdiction'. Given a participating jurisdiction must have passed a version of the NEL, an EBA made under the Commonwealth's Fair Work Act 2009 appears to be imposed by a law other than of a participating jurisdiction. Further, the terms of an EBA itself are not contained in the Fair Work Act 2009.*

534 The Tribunal's conclusion that the EA may reasonably be regarded as satisfying the capex objective and capex criterion, was presumably drawn from the following statement in the above passage:

> *This is because the terms of an EBA could plausibly materially affect a service provider's provision of standard control services.*

535 However that passage emerged only in the context of the AER attempting to find a category of regulatory obligation or requirement under s 2D to which an EA could logically "fit". It considered the most logical fit was with the category dealing with an Act or instrument that materially affects the provision of electricity network services. The AER was not suggesting from the above passage that it had in fact concluded that an EA materially affects a service provider's provision of standard control services. Rather that was the only working category that could possibly fit within the requirements of s 2D. Hence the AER's use of the expression "plausibly".

536 SAPN also referred to the following passage from *Ausgrid* in support of its position at [436]:

> ***It may be said that, in the view of the Tribunal, it is the policy of the legislative arm***

> ***of government that, to the extent that the EBA's are (if they are) an inefficient imposition on the DNSPs, nevertheless they are a cost to be borne by the consumers of electricity.*** *… [H]aving regard to the regulatory prescriptions, the Tribunal does not accept that [the AER] may, by the use of the EI model [proposed by the AER], simply select the measurement of efficiency which it did in this respect without regard to the obligations under the EBAs as they presently exist. Over time, and probably during the new current regulatory period, any such inefficiencies as the AER considers to exist may progressively be reduced … and any allowances under the EBAs (as they expire) which the AER considers to be inefficient may also by the same elapse of time be reduced to an efficient level.*
>
> (Emphasis added).

537 SAPN relies on the highlighted passage for the proposition that it is the policy of the legislative arm of government to permit EAs, almost without regard to their cost impact.

538 That is not what the Tribunal in *Ausgrid* conveys by that passage. It is important to understand the context in which it arose. The AER had relied on a model prepared for it by Economic Insights Pty Limited ('**EI**'). What came to be known as the EI model was an econometric benchmarking model which arose from two reports EI prepared for the AER. The model was relied on by the AER in determining the appropriate opex. The relevant parties challenged the manner in which the AER had applied that model including the inputs it used.

539 Although the AER appears to have recognised that the terms of an EA can affect a DNSP's delivery of standard control services, nevertheless, in applying the EI model, the AER purportedly treated costs arising under the EAs as an endogenous factor to be ignored in the AER's estimate of the total required opex (see [421]-[423] of *Ausgrid*). The Tribunal then said at [427]:

> *Thus, although the EBAs may lack either the NEL's s 2D jurisdictional foundation or the genus of a safety or reliability standard etc of a r 6.5.6(a)(3) "regulatory requirement or obligation", the Networks NSW DNSPs are bound by their EBAs as a matter of law. Unlike a contract, which according to its terms may be terminated, an EBA continues in force until its nominal expiry date after which it may, with the approval of the Fair Work Commission, be terminated by agreement between an employer and the employees it covers (ss 219-224 of the Fair Work Act 2009 (Cth)). Absent agreement, an application must be made to the Fair Work Commission to terminate an EBA. Termination may only occur if the Commission is satisfied that to do so is not contrary to the public interest and is appropriate in all the circumstances (ss 225-227 of the Fair Work Act 2009 (Cth)).*

540 In the opening part of this passage it said:

> *Thus, although the EBAs may lack either the NEL's s 2D jurisdictional foundation or the genus of a safety or reliability standard etc of a r 6.5.6(a)(3) "regulatory requirement or obligation", the Networks NSW DNSPs are bound by their EBAs as a*

matter of law.

541 The Tribunal is there suggesting that an EA does not attract the regulatory obligation of s 2D or indeed the safety and reliability standard of cl 6.5.6(a)(3). This of course also lends further support to our view that SAPN's EA is not a regulatory obligation. It is then said "Networks NSW DNSPs are bound by their EBAs as a matter of law". Having already rejected the application of s 2D and cl 6.5.6(a)(3), the Tribunal must be referring to the fact that a DNSP is bound by an EA only in the sense that a failure to comply would constitute a breach and attract penalties under the FW Act. That interpretation is supported by the remainder of the passage where the Tribunal discusses the limited rights to terminate an EA – reinforcing the point that an EA is binding on a DNSP as a matter of law.

542 It is after this discussion that paragraph [436] of the Tribunal's reasons emerge on which SAPN relies. When the Tribunal refers in that paragraph to "the policy of the legislative arm of government that, to the extent that the EBA's are (if they are) an inefficient imposition on the DNSPs, nevertheless they are a cost to be borne by the consumers of electricity", it is referring to the fact that an EA is binding in the sense in which they had previously used it. That is, the Tribunal is suggesting it could not have been the policy intent of the legislature to permit the AER (relevantly when applying the EI model) to ignore the binding nature of an EA and to treat it wholly as an endogenous factor which could be ignored by the AER. It is not suggesting that the cost impacts of an EA should, as matter of policy expressed by the legislature, be disregarded entirely or conversely, automatically adopted.

543 Accordingly the Tribunal rejects SAPN's reliance on this aspect of the *Ausgrid* decision.

544 Even if our assessment of *Ausgrid* is incorrect, SAPN's argument that the EA is necessary to maintain the safety of the distribution system and falls within the opex and capex objectives of the NER should be rejected.

545 First, the provision still requires that SAPN demonstrate that the EA is necessary to "maintain the safety of the distribution system through the supply of standard control services". As explained in the earlier consideration of cl 6.5.6(a)(2) and s 2D, there must be a direct connection between the EA and the delivery of standard control services. That connection is the labour employed to deliver those services, not the mechanism chosen to provide that labour.

546 Secondly, the capex and opex objectives apply to the total estimates for capex and opex. The labour cost escalator is one such factor. It cannot be assumed that any error with respect to the labour cost escalator would completely undermine the capex and opex objectives applying to the safe delivery of standard control services.

Compliance with the capex criteria

547 As SAPN's contention that the EA is a regulatory obligation or is otherwise necessary to maintain the safety of the distribution system under the opex and capex objectives is rejected, it is unnecessary to consider whether the EA satisfies the capex criteria. Were it necessary to do so, the Tribunal would find that the capex criteria is not satisfied. The Tribunal sets out briefly its reasons for this view.

548 SAPN argues that its EA was negotiated at arm's length in good faith and represents current market conditions for electricity workers in South Australia. Its labour escalations cover almost 95% of its employees, and others (such as contractors) are effectively bound to the EA through a contractor parity clause requiring the payment of EA rates of pay. SAPN also submits that the use of the benchmark EAs is a preferable methodology than the EGWWS WPI suggested by the AER and provides a more reasonable and transparent forecast for the labour price rate of change.

549 It should be noted that the labour cost escalator is applied to a broader category of costs than simply internal labour. To forecast price growth, the AER uses a weighted average of forecast labour price growth and forecast non-labour price growth. The implications therefore extend beyond SAPN's EA issues alone.

550 The EA must satisfy the prudency and efficiency tests under the opex and capex criteria. The mere negotiation of an EA, albeit in good faith and at arm's length, is not itself an adequate foundation for discharging the opex and capex criteria. As earlier explained, the nature of an EA leaves itself open to considerable management discretion on terms, even if they may arise from employee demands. It would be important, for example, to demonstrate productivity and other improvements, consistent with wage conditions in the industry.

551 Finally SAPN has not mounted a compelling challenge in face of the considerable sectoral wage growth data and wage growth trends relied on by the AER.

Conclusion

552 For the reasons given, the Tribunal concludes that the AER did not make an error of fact or facts that was material to the making of the decision, that the exercise of the AER's discretion was not incorrect or the decision unreasonable, having regard to all the circumstances.

Forecast inflation

553 Under cl 6.4.3(a) of the NER, the annual revenue requirement for a DNSP for each regulatory year of a regulatory control period must be determined using a building block approach.

554 The indexation of the regulatory asset base building block is in effect, a deduction from the annual revenue requirement equal to the amount that is referred to in cl S6.2.3(c)(4) – that is, the amount necessary to maintain the real value of the regulatory asset base as at the beginning of the subsequent year by adjusting that value for inflation.

555 The deduction from the annual revenue requirement is needed to avoid "double counting" of inflation. Under the NER, a nominal rate of return is used in combination with an inflation-adjusted regulatory asset base. Thus, without any adjustment, service providers would be compensated twice for the effects of inflation – once through the rate of return and again through indexation of the regulatory asset base. The way this is addressed in the NER is to provide for a negative adjustment as described.

556 If there is a mismatch between forecast and actual inflation, there will be an inconsistency between the amount by which the regulatory asset base is increased over time to account for inflation and the corresponding deductions from the revenue allowance.

557 The AER is required to specify appropriate methods for the indexation of the regulatory asset base and any other amounts, values or inputs on which its building block determination is based. It is therefore necessary for the AER to determine an appropriate forecast of inflation as part of each distribution determination.

The AER's Final Decision

558 In its Regulatory Proposal, SAPN adopted an inflation forecast of 2.55%. This was based on the method applied by the AER in its distribution determination for the prior regulatory control period, which is to take a geometric mean 10-year forecast based on:

- for the first two years of the regulatory control period, the mid-point of the RBA forecast range for CPI inflation; and

- for subsequent years, the mid-point of the RBA target range for CPI inflation.

559 SAPN submitted a Revised Proposal in light of what it says were concerns that the method it adopted in its Regulatory Proposal was no longer producing accurate forecasts.

560 In its Revised Proposal, SAPN adopted a different forecasting method which produced an inflation forecast of 2.06% for the 2015-2020 period. The revised forecasting method was based on a report by consultant Competition Economists Group (‘**CEG**’) “Measuring expected inflation for the PTRM” June 2015 and is referred to as the “breakeven” inflation forecasting method. Under the CEG “breakeven” method, an estimate of expected inflation is derived from the difference in yields on nominal and inflation-indexed Commonwealth Government Security (‘**CGS**’) of the same maturity.

561 SAPN’s concern and that of CEG was that due to changes in market conditions, it was no longer reasonable to expect inflation to revert to the middle of the RBA target range over the medium term. The evidence presented by CEG indicated that over the medium term, inflation is likely to be below the mid-point of the RBA target range. Therefore in current market conditions a methodology that assumes medium-term inflation would be at or around the mid-point of the RBA target range is likely to overestimate forecast inflation.

562 SAPN’s alternative methodology presented in its Revised Proposal was said to overcome this limitation by relying on market-based measures of inflation expectations. The “breakeven” inflation forecasting method does not involve any assumption as to medium-term inflation. Rather, the “breakeven” method is a measure of market expectations of inflation, as indicated by the difference in market yields on nominal and inflation indexed CGS of the same maturity.

563 In the Final Decision, the AER adopted an inflation forecast of 2.5% for the 2015-2020 regulatory control period. This was based on the methodology that had been adopted by the AER in its prior determination, namely:

- for the first two years of the regulatory control period, taking the mid-point of the RBA forecast range for CPI inflation. At the time of the AER’s Final Decision, the RBA had published a forecast range of 2-3% for these two years, with a mid-point of 2.5%; and
- for subsequent years, taking the mid-point of the RBA target range for CPI inflation, also 2.5%.

564 The AER provided the following reasons for rejecting SAPN's alternative methodology (Final Decision, Attachment 3, pp 253-4):

> *We do not accept SA Power Networks' new method for the following reasons:*
>
> - *Changing the method after we accepted the original proposal in the preliminary determination is inconsistent with the intent of the regulatory process. Stakeholder submissions on our preliminary determination were made on the basis that the inflation estimation method is not under consideration in the final decision.*
> - *The rules mandate a nominal vanilla WACC. Consequently, the inflation estimate is not a direct input parameter for deriving the rate of return that contributes to the achievement of the allowed rate of return objective. This is consistent with a broader reading of the NER, and in particular the express requirement for inflation and taxation to be addressed through the PTRM.*
> - *An amendment to the PTRM is a distinct and separate process to the assessment of an NSP's proposal. It must follow the specific timeframes set out by the distribution consultation procedures. Moreover, good regulatory practice requires a comprehensive consultation process as a prerequisite before changing the method for estimating a parameter that impacts all NSPs and users across multiple building blocks thereby affecting total revenue estimates.*

565 The AER then explored features of the model used by SAPN and considered that the research, analysis and reasoning submitted to the AER should be subject to review through a comprehensive process allowing effective engagement with all stakeholders. The AER then pointed to the importance of the PTRM process in determining forecast inflation (Final Decision, Attachment 3, p 255):

> *Under both the NER and NGR, an inflation forecast is required for modelling revenue over the next regulatory control period. The NER mandates the use of the AER's Post tax revenue model (PTRM). The NGR does not mandate the use of the PTRM, but requires service providers to provide financial information on a nominal basis or real basis or some other recognised basis for dealing with the effects of inflation. Under the NER, the AER's published PTRM must include a method the AER determines is likely to result in the best estimate of inflation. Under the NGR, a service provider must propose an estimate on a reasonable basis which is the best forecast or estimate possible in the circumstances. United Energy stated that the appropriate approach to address concerns with our current method was to undertake an amendment to the PTRM.*
>
> *Any changes/amendments to the PTRM must be done in accordance with the distribution consultation procedures.*

566 The AER indicated that under cl 6.5.2(d)(2) of the NER, subject to achieving the rate of return objective, it is required to determine a rate of return on a nominal vanilla weighted average cost of capital basis. The AER said that under the nominal vanilla approach an inflation forecast is therefore not a direct input in determining the allowed rate of return.

567 The AER also expressed its satisfaction with its current approach as reflecting the views of stakeholders (Final Decision, Attachment 3, p 256):

> *In our recent rate of return guideline development consultation process we raised the inflation method as an issue for potential review. We noted that the indexed bond market had changed since we departed from the Fisher equation, and asked for submissions on whether we should change the approach. We also noted different methods and what other regulators were adopting. In response, stakeholders endorsed the continuation of the current approach. We therefore are satisfied that the current approach is the appropriate approach for this determination.*

568 For these reasons the AER did not consider the method for forecasting inflation as part of its distribution determination for SAPN. The AER did not rule out a change to the method of inflation forecasting. However in its view this needed to be undertaken in accordance with the consultation processes mandated by the NER. The next rate of return guideline review was considered a more suitable process for reviewing the inflation forecasting method.

Areas of dispute

569 SAPN contends that the AER incorrectly exercised its discretion in failing to consider the merits of SAPN's methodology and in rejecting the proposed methodology on the basis that it was different to that originally proposed by SAPN.

570 SAPN also contends that the AER made a number of errors of fact including forming an opinion as to the existence of future inflation. The AER rejects this as not an issue of fact but rather a statement of opinion.

571 SAPN also points to other errors made by the AER.

572 It is unnecessary to go into more detail about the errors contended by SAPN. This is because counsel for both parties acknowledged that the dispute now had a fairly narrow scope. It is whether the PTRM is binding such that the AER cannot consider inflation outside an amendment to the PTRM or whether, as SAPN contends, although there is a reference to inflation in the PTRM, the AER in fact has to give separate consideration to that issue under the NER in making its Final Decision.

573 The dispute will therefore be resolved on the correct interpretation of the NER. For this reason it is also unnecessary to consider the suitability of SAPN's alternative methodology or indeed the inflation forecasts derived under that methodology.

Arguments advanced by SAPN

574 SAPN accepts that the inflation estimate is not a direct input parameter for deriving the nominal rate of return under cl 6.5.2. However, SAPN argues that just because it is not an input into the nominal rate of return does not mean that the inflation forecasting methodology cannot fall for consideration by the AER as part of making a distribution determination.

575 SAPN argues that the NER does not require that the inflation forecast used to calculate the indexation of the regulatory asset base building block be determined in accordance with the inflation forecasting method specified in the PTRM.

576 On the contrary, SAPN says that as part of each distribution determination the AER is required to specify appropriate methods for the indexation of the regulatory asset base and any other amounts, values or inputs on which its building block determination is based. It is therefore necessary, as part of each distribution determination, for the AER to determine an appropriate forecast of inflation.

577 For consistency with their context and purpose, SAPN submits that the relevant provisions of Ch 6 are to be read as requiring the AER to determine an appropriate forecast of inflation as part of each distribution determination. In contrast, the AER's approach is said to be rigid and will produce an inflation forecast that is too high resulting in a total revenue allowance (all other things being equal) that is less than what is required to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers.

578 SAPN also points out that under the AER's approach, the inflation forecasting method is one input that can be effectively locked in by the AER, without any opportunity for stakeholders to have that method reviewed. The AER recognises that the methods used to determine other inputs (eg gamma, rate of return inputs and expenditure forecasting methods) must be considered as part of each determination. It is therefore unclear why the method for forecasting inflation should be treated any differently.

Arguments advanced by the AER

579 Contrary to SAPN's position, the AER submits that the NER requires the inflation forecast used to calculate the indexation of the regulatory asset base building block to be determined in accordance with the inflation forecasting method specified in the PTRM. This is said to flow from cl 6.3.1 and cl 6.4.2 of the NER.

580 Clause 6.3.1(c)(1) stipulates that a building block proposal must be prepared in accordance with the PTRM and cl 6.4.2(b)(1) stipulates that the PTRM must include a method that the AER determines is likely to result in the best estimates of expected inflation. The PTRM published by the AER includes a method for forecasting inflation and the AER applied that method in its building block determination under cl 6.12.1.

581 As noted, SAPN relies on various clauses in the NER to argue that the inflation method specified in the PTRM is not mandatory. The AER submits that those other clauses cannot be read in a manner that contradicts the plain meaning of cl 6.3.1(c)(1) and cl 6.4.2(b)(1). For example, SAPN relies on cl 6.12.1(2)(i) which provides that one of the constituent decisions of the overall distribution determination is a decision on the DNSP's current building block proposal in which the AER either approves or refuses to approve the annual revenue requirement for the DNSP as set out in the building block proposal. However the AER says that the contents of the building block proposal are governed by Pt C of Ch 6, and cl 6.3.1(c) stipulates that the building block proposal must be prepared in accordance with the PTRM.

582 The AER also points out that the PTRM provides certainty, consistency and continuity to DNSPs in the regulation of required revenue. Although the PTRM is not fixed, nevertheless the NER establishes a consultation process for amendment which involves all DNSPs as all DNSPs are impacted by the PTRM. The AER's position is not that it could never consider a change to the PTRM at the same time as a distribution determination. However it maintains it is required to comply with the distribution consultation procedures, which evidence an intention on the part of the rule makers that broad consultation occur across the industry before any change is made.

Tribunal's consideration

583 The AER concedes there is no express provision in the NER that prohibits it from considering inflation forecasts outside the PTRM process. Rather its position follows from the overall construction of the NER. Equally SAPN did not point to a provision of the NER that expressly requires the AER to consider its inflation forecast, other than as part of the usual considerations that should inform the AER's decision-making, like other factors it considers in making its Final Decision.

584 Therefore the position of both parties ultimately turns on the overall construction of the NER.

The PTRM

585 It is useful at the outset to gain some understanding of the PTRM.

586 The PTRM is defined in the NER Glossary as the model prepared and published by the AER in accordance with cl 6.4.1.

587 The AER must, in accordance with the distribution consultation procedures, prepare and publish a PTRM: cl 6.4.1(a). The AER must ensure that a PTRM is in force at all times: cl 6.4.1(c).

588 The PTRM must set out the manner in which the DNSP's annual revenue requirement for each regulatory year of a regulatory control period is to be calculated: cl 6.4.2(a).

589 The contents of the PTRM must include (but are not limited to the following (NER cl 6.4.2(b)):

> *(1) a method that the AER determines is likely to result in the best estimates of expected inflation; and*
>
> *(2) the timing assumptions and associated discount rates that are to apply in relation to the calculation of the building blocks referred to in clause 6.4.3; and*
>
> *(3) the manner in which working capital is to be treated; and*
>
> *(4) the manner in which the estimated cost of corporate income tax is to be calculated.*

590 The AER may amend the PTRM from time to time, in accordance with the distribution consultation procedures: cl 6.4.1(b). The distribution consultation procedures are those procedures set out in Pt G of Ch 6. Broadly, the distribution consultation procedures specify the consultation steps the AER must employ, including the use of explanatory materials and the requirement to seek comments from interested parties before making a relevant decision.

591 In practical terms, the PTRM is an excel spreadsheet. The Tribunal was taken to a brief demonstration of its application. From the illustration (and as counsel explained) the PTRM is a excel file that contains various cells corresponding to various parameters required in arriving at a final decision on building blocks. A DNSP is required to input numbers into various cells. As we understand, other aspects of the PTRM have been preset within the model, for example the inflation forecast. When the model is run those preset features apply to the remainder of the inputs made by a DNSP.

592 In that way the AER can assess the responses consistently across all DNSPs, with the knowledge that the features of the model will automatically have been incorporated, including the preset parameters.

593 It should be noted that although the Tribunal was provided with a brief illustration of an extract of the PTRM, the full PTRM, the process by which it is determined and practically applied was not the subject of any significant evidence. Given the way in which the arguments were presented, presumably a greater understanding of the PTRM is not required as ultimately the issue turns on the proper place of the PTRM in the scheme of regulation under the NER.

594 The PTRM is expressly employed in some parts of the NER. For example, the formula specified in cl 6.5.3 in estimating the cost of corporate income tax expressly requires that the estimate of taxable income be determined using the PTRM. It is also used to calculate incremental revenue in circumstances where a DNSP has applied under cl 6.6.2 to vary a determination where a trigger event for a contingent project in relation to that determination has occurred.

595 One immediate observation to make is that the rule makers sought to expressly include a PTRM in the NER, specified the matters it should contain and how the PTRM should be amended. Having gone to those lengths, there is a strong suggestion that the rule makers intended the PTRM to occupy a particular place in the scheme of regulation in the NER.

596 It appears that the first PTRM was published in 2008, the second version in 2009 and the current version (version 3) was published in January 2015.

The NER and the PTRM

597 As indicated, cl 6.3.1(c)(1) directs that a building block be prepared in accordance with the PTRM. For the AER this indicates that a DNSP cannot depart from a parameter preset in the PTRM. However SAPN places a different construction on the clause having regard to the practical workings of the PTRM itself. For SAPN, what that clause requires is only that a DNSP submit numbers in accordance with that model so that the AER can coherently consider the data at its end. That is, the direction given by cl 6.3.1(c)(1) is only to use the model, not that the preset parameters themselves are beyond challenge in submitting a proposal to the AER.

598 To reconcile the direction given by cl 6.3.1(c)(1) with a different inflation forecast to the PTRM, SAPN distinguishes between two phases of a proposal. Under the first phase, the building block proposal must, as required by cl 6.3.1(c)(1), be submitted in terms of the model that is the PTRM. But then different considerations are said to apply in the second phase – the making of the determination.

599 Clause 6.3.2 in this second phase specifies the matters that must be considered in making a building block determination. One of those matters is in cl 6.3.2(a)(2) – the appropriate methods for the indexation of the regulatory asset base. SAPN says that provision stands alone and is not constrained by the PTRM. Certainly there is no express reference there to the PTRM. Of course the AER's response is that there is no need to mention it because if a DNSP complies with cl 6.3.1(c)(1), then the PTRM will have dealt with the issue through the preset parameters in the PTRM.

600 Chapter 6 does step through the process for the making of a building block determination in fairly a sequential way. It starts as both parties acknowledge, with a DNSP submitting a building block proposal to the AER under cl 6.3.1(b). The sequential nature of the process is effectively described in that provision. It also then notes that Pt E will apply to the making of the building block determination.

601 As noted, cl 6.3.1(c)(1) directs that the proposal "be prepared in accordance with the post-tax revenue model". It is significant that cl 6.3.1(c)(1) employs the word "prepared". If all that were required is that a DNSP simply submit its proposal under the form of the PTRM, then the NER could simply have directed that a proposal be submitted using the PTRM framework or some similar form of words. It does not do that. It suggests that the PTRM is more than simply an excel template to be used by each DNSP. The PTRM carries substantive parameters that must be employed by a DNSP in submitting a proposal.

602 Immediately following is r 6.4 which deals with the contents of the PTRM referred to above. In one sense, having introduced the concept of a PTRM in cl 6.3.1 it is obviously sensible to describe what it should contain. However, it would have been easy for the drafters of the NER to deal with the PTRM in a schedule or elsewhere in Ch 6. However they choose to interpose it between the contents of a building block determination and the building block approach. This is also because the PTRM is more than a mere tool in which to submit a proposal.

603 The drafting of r 6.4 also lends support to this view. First, cl 6.4.1(c) requires the PTRM to be “in force” at all times. It is not merely that the PTRM be available for use. Secondly, the PTRM cannot be amended at a whim. It can only be amended under the distribution consultation procedures. There would be little point in the rule makers establishing such a significant “gatekeeping” requirement if the PTRM were little more than a tool in which to submit a proposal. Finally, the PTRM must establish a “method” that the AER determines is likely to result in the best estimates of expected inflation (cl 6.4.2(b)(1)). The requirement to establish a “method” is a far stronger and significant direction than simply to establish a tool by which to submit a proposal.

604 Following this sequence, cl 6.4.3(a)(1) then specifies that one of the building blocks in calculating the annual revenue requirement is the indexation of the regulatory asset base. For the purposes of indexing the regulatory asset base cl 6.4.3(b)(1) provides that the regulatory asset base is to be calculated under cl 6.5.1 and Sch 6.2 and that the building block comprises a negative adjustment equal to the amount referred to in cl S6.2.3(c)(4) for that year. This is the source of the negative adjustment referred to earlier.

605 It is in the context of the roll forward of the regulatory asset base that S6.2.3(c)(4) provides:

> *(c) Method of adjustment of value of regulatory asset base*
>
> *The value of the regulatory asset base for a distribution system as at the beginning of the second or a subsequent year (the later year) in a regulatory control period must be calculated by adjusting the value (the previous value) of the regulatory asset base for that distribution system as at the beginning of the immediately preceding regulatory year (the previous year) in that regulatory control period as follows:*
>
> …
>
> *(4) The previous value of the regulatory asset base must be increased by an amount necessary to maintain the real value of the regulatory asset base as at the beginning of the later year by adjusting that value for inflation.*

606 It will be seen that what cl S6.2.3(c)(4) directs is that the regulatory asset base be adjusted for the effect of inflation.

607 Clause 6.5.1(b) requires that the AER in accordance with the distribution consultation procedures, develop and publish a model (the ‘**roll forward model**’) for the roll forward of the regulatory asset base. The AER may amend or replace the roll forward model from time to time in accordance with the distribution consultation procedures: cl 6.5.1(c). The purpose of the roll forward model (as the name suggests) is to deal with movements from one

regulatory control period to the next. Clause 6.5.1(e)(3) requires in particular that the roll forward model set out the method for determining the roll forward of the regulatory asset base for distribution systems under which:

> *(3) the roll forward of the regulatory asset base from the immediately preceding regulatory control period to the beginning of the first regulatory year of a subsequent regulatory control period entails the value of the first mentioned regulatory asset base being adjusted for actual inflation, consistently with the method used for the indexation of the control mechanism (or control mechanisms) for standard control services during the preceding regulatory control period.*

608 The clause refers to adjustments for actual inflation in the case of the first roll forward. Clause 6.5.1(f) provides that "[o]ther provisions relating to regulatory asset bases are set out in schedule 6.2". In other words, there is a reference to Sch 2 in both cl 6.4.3(b) dealing with the specification of the building blocks and also through cl 6.5.1.

609 It should be noted that neither cl S6.2.3(c)(4) nor cl 6.5.1(e)(3) expressly refer to the adjustment for inflation or the roll forward of the regulatory asset base occurring consistently with the PTRM. SAPN argues that the AER should therefore determine an appropriate forecast for inflation without being constrained by the PTRM. For if it were constrained by the PTRM that rigid approach would be inconsistent with the framework of the NER that looks to a revenue allowance that allows a DNSP to recover efficient costs. An inflation forecast that is too high or low (through slavish reliance on the PTRM) would be inconsistent with that framework. The AER's response is that these provisions do not deal with inflation because inflation is embedded in the PTRM from the first moment a DNSP is directed to submit its building block proposal.

610 To understand the AER's argument it is necessary to return to the next step in the sequence in the making of a determination. The remaining provisions in Pt C then proceed to address features of the other building blocks such as the return on capital and depreciation. Having dealt with those building blocks, Pt E then logically addresses the determination process. That starts with a DNSP submitting a regulatory proposal to the AER under cl 6.8.2. The regulatory proposal must include a building block proposal: cl 6.8.2(c)(2). Following consultation the AER is required to publish a draft determination which also includes a consultation process: cl 6.10.1(a). A DNSP is required to respond to a draft determination by submitting revisions "so as to incorporate the substance of any changes required to address matters raised by the draft distribution determination or the AER's reasons for it": cl 6.10.3(b). A related criticism made by the AER is that this precludes SAPN submitting a

new inflation methodology as it is not in truth a response to the draft determination. In view of the Tribunal's ultimate conclusion, it is unnecessary to consider the merits of that argument.

611 The final stage in the sequence is the making by the AER of a final determination: cl 6.11.1.

612 Clause 6.12.3 deals with the extent of the AER's discretion in making a distribution determination. Clause 6.12.3(a) provides:

> *Subject to this clause and other provisions of this Chapter 6 explicitly negating or limiting the AER's discretion, the AER has a discretion to accept or approve, or to refuse to accept or approve, any element of a regulatory proposal or proposed tariff structure statement.*

613 One aspect of the AER's discretion in approving the annual revenue requirement is dealt with in cl 6.12.3(d):

> *The AER must approve the total revenue requirement for a Distribution Network Service Provider for a regulatory control period, and the annual revenue requirement for each regulatory year of the regulatory control period, as set out in the Distribution Network Service Provider's current building block proposal, if the AER is satisfied that those amounts have been properly* ***calculated using the post-tax revenue model*** *on the basis of amounts calculated, determined or forecast in accordance with the requirements of Part C of this Chapter 6.*
>
> (Emphasis added).

614 The effect of cl 6.12.3(d) is that the AER has no discretion but to approve the total revenue requirements for a DNSP if it is satisfied that it has been calculated using the PTRM. It is significant that the clause requires the amounts to have been "calculated" using the PTRM. That expression ascribes to the PTRM a status more than merely a device or tool in which a proposal should be submitted. Ultimately it plays a material part in the determination of the total revenue requirement. It is also significant that both SAPN and the AER are bound by the PTRM through this clause. It is no more open to the AER to substitute an alternative inflation forecast through the building blocks than it is for SAPN. This is because the AER has no discretion but to approve a revenue requirement that has been calculated using the PTRM.

615 What this journey reveals is that the PTRM features at the very beginning of the determination process (when a DNSP is directed to submit a building block proposal that complies with the PTRM) and at the very end of the process when the AER is obliged to approve a revenue requirement (reflecting the building blocks) calculated using the PTRM. The common link between the start and end of the process is the PTRM. Having given the

PTRM such a central place the rule makers did not see a need to expressly refer to it again in any of the intermediate stages or for example in dealing with the roll forward provisions.

616 At this stage it is worth returning to SAPN's fundamental criticism of AER's approach – that it is too rigid and will produce and inflation forecast that is too high resulting in a total revenue allowance (all other things being equal) that is less than what is required to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers. There are several difficulties with this argument. First it assumes that SAPN's methodology and the inflation forecast it derives is correct. That has not been established. Indeed the distribution consultation procedures ensure that these arguments can be fully ventilated and debated before a new PTRM is established. SAPN has the opportunity to put forward the model and have it "tested" as part of that process.

617 Secondly, the rule makers have determined to give the PTRM an express role within the NER as we have explained – presumably to ensure consistency between DNSP's and regulatory decisions. Having done so, the AER must comply. That is no more rigid an approach than the requirement to comply with other directives in the NER.

618 Finally, cl 6.4.1(b) permits the AER to amend or replace the PTRM from time to time. There are no limits on how many times it may do so. Further the distribution consultation procedures do not appear to preclude a review of the PTRM occurring during the distribution determination process, if there is adequate time within the consultation procedures in which to do so. In that way a DNSP need not be prejudiced should it wish to advance an alternative model as SAPN sought to do.

Conclusion

619 For the reasons given, the Tribunal concludes that the PTRM is binding on SAPN and the AER such that AER cannot consider inflation outside the PTRM, as proposed by SAPN. Accordingly the Tribunal concludes that the AER did not make any error.

CONCLUSION

620 As no error has been found in the Final Decision, it is unnecessary to consider the operation of s 71P(2a)(c) of the NEL.

621 In view of the above reasons, the determination of the Tribunal is that the Final Decision is affirmed.

I certify that the preceding six hundred and twenty one (621) numbered paragraphs are a true copy of the Reasons for Determination herein of the Honourable Justice Middleton, Professor KT Davis and Mr R Steinwall.

Associate:

Dated: 28 October 2016