ACCESS DETERMINATION

South Australia Public Lighting 2010 to 2015

26 September 2019

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Contents

Shortened forms

Shortened form	Extended form
ACS	alternative control services
AER	Australian Energy Regulator
CAM	cost allocation method
capex	capital expenditure
CPI	consumer price index
dispute period	1 July 2010 to 30 June 2015
EDPD	Electricity Distribution Price Determination, made pursuant to the Essential Services Commission Act 2002 (South Australia)
EO	Energy Only service
EPO	Electricity Pricing Order 1999, made pursuant to the Electricity Act 1996 (South Australia)
ERP	Expert Review Panel
ESCOSA	Essential Services Commission of South Australia
NDSC	Negotiated Distribution Service Criteria
NEL	National Electricity Law
NER	National Electricity Rules
NEO	National Electricity Objective
NPV	net present value
ODRC	optimised depreciated replacement cost
O&M	operating and maintenance
PLC	Public Lighting Customers
PTRM	Post-Tax Revenue Model
Public Lighting Customers	The Department of Planning, Transport and Infrastructure of the Government of South Australia and the 61 South Australian councils and municipalities listed in Attachment A to HWL Ebsworth's letter to the AER dated

	2 May 2017
public lighting services	In this document unless otherwise stated 'public lighting services' means SLUOS Services. In the regulatory instruments governing electricity distribution services in South Australia 'public lighting services' means SLUOS services, Customer Lighting Equipment Rate Services and Energy Only Services.
RCM	recovered capital method
regulatory principles	the NEO, RPPs, NDSCs and relevant provisions of Chapter 6 of the NER
RFM	Roll-Forward Model
RPPs	revenue and pricing principles
RAB	regulatory asset base
SAIIR	South Australian Independent Industry Regulator
SAPN	SA Power Networks
SKM	Sinclair Knight Mertz
SLUOS Service	Street Lighting Use of System Service
TAB	tax asset base
WACC	Weighted Average Cost of Capital
WDV	Written-down value

1 Introduction

1.1 Purpose

This document sets out the elements of and reasons for our determination for the access dispute concerning public lighting charges in South Australia in the period 1 July 2010 to 30 June 2015 (the 'dispute period').

Accompanying this determination are three reports by Sapere Research Group- the AER's economic consultant - and two Excel workbooks.[1]

1.2 Decision

Our determination on the contested issues for the dispute period is as follows:

1. The opening Regulatory Asset Base (RAB) at 1 July 2010 is $34.79 million.
2. The opening Tax Asset Base (TAB) at 1 July 2010 is $15.96 million.
3. Corporate overheads are not to be reallocated in consequence of our decision on RAB and TAB.
4. Elevation charges are not included in the public lighting cost base.
5. The discount rate for any under-recovery or over-recovery of revenue for the dispute period is the regulatory weighted average cost of capital (WACC) applicable to SAPN, adjusted for outturn inflation, from the commencement of the dispute period until the date upon which repayment is made.
6. Using the PTRM, we determine that SA Power Networks' (SAPN) public lighting revenue exceeded its efficient costs over the dispute period. The present value of the over-recovery at 30 September 2019 is $13,008,154.01.

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1 Sapere Research Group, Modelled results for AER access determination: South Australia Public Lighting 2010-2015, September 2019.

Sapere Research Group, Modelling SAPN street lighting asset base and revenue 2010-2015, 22 January 2019;

Sapere Research Group, The SA public lighting access dispute: the PTRM principles, 19 May 2018.

'D_PTRM_v3Jan2015_x_Regulatory_SRG_.xlsm' as updated by Sapere Research Group, 20 September 2019.

'SAPN RollForward and PTRM Model ReleaseVersion.xlsm' as updated by Sapere Research Group, 20 September 2019.

2 Background

2.1 Parties

The parties to this access dispute are:

- The Department of Planning, Transport and Infrastructure of the Government of South Australia and the 61 South Australian councils and municipalities listed in Attachment A to HWL Ebsworth's letter to the AER dated 2 May 2017 (collectively the Public Lighting Customers or PLCs)
- SA Power Networks (SAPN). SAPN owns the electricity distribution network in South Australia and is the provider of the public lighting services that are the subject of this dispute. SAPN was previously named ETSA Utilities. When we refer to this party in this determination, we use the name that applied to it at the relevant time (ETSA Utilities or SAPN).

The PLCs contend they have been overcharged by SAPN for public lighting services. The nature of the matters in dispute is described in more detail below.

2.2 Public lighting services

In these Reasons, the term 'public lighting services' refers to Street Lighting Use of System Services (or SLUOS Services), which are the subject of the dispute. The SLUOS Service is defined as: [2]

> *The provision of public lighting assets, and the operation and maintenance of those assets where ETSA Utilities retains ownership of the assets.*

Two more services - which are not the subject of the dispute - are also described as 'public lighting services' under various regulatory instruments. These are:[3]

- Customer Lighting Equipment Rate (CLER) Service - being 'the replacement of failed lamps in customer-owned streetlights where the customer retains ownership of the assets and is responsible for all other maintenance'
- Energy Only Service - described as 'the maintenance of a database relating to street lights, and recording and informing customers of streetlight faults reported to ETSA Utilities where customers retain ownership of the assets and are responsible for all maintenance (including replacement of failed lamps).

To be clear, unless stated otherwise, the expression 'public lighting services' is used in these Reasons to refer only to SLUOS services and not CLER or Energy Only Services.

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[2] AER, Final Decision: South Australian Distribution Determination 2010/11 to 2014-15, p. 284.

[3] The original dispute notice from the Local Government Association of SA dated 9 December 2013 refers specifically to SLUOS charges. The subsequent letter from HWL Ebsworth Lawyers on behalf of the PLCs (2 May 2017) refers to 'public lighting services,' but the attached Houston Kemp report (2 February 2017), which is effectively PLC's submission in chief, states the dispute relates to SLUOS services. An expert's report provided by SAPN notes public lighting includes SLUOS and CLER and 'this report is concerned only with SLUOS charges': Incenta Economic Consulting, Determining the value of SAPN's public lighting assets, August 2017, para 2, p. 1.

2.3 Procedural history

2.3.1 Initial access dispute and alternative dispute resolution

On 9 December 2013 the Local Government Association of South Australia gave notice of a dispute pursuant to Part 10 of the NEL concerning the charges for SLUOS services provided by SAPN to 66 South Australian Councils.[4] The Local Government Association sought a determination that:[5]

- the charge for public lighting services should be $11.35 million per annum in aggregate with annual increases of 25 percent of CPI, reducing to $2.4 million per annum from 1 July 2014 by which time the relevant assets would be fully depreciated
- pre-payments by the customers be accounted for either within SAPN's public lighting charges or by way of a refund to the customers.

The AER directed the parties under section 129 of the NEL to attempt to resolve the dispute by alternative dispute resolution. In the course of this the parties referred a number of questions to an Expert Review Panel (ERP) for non-binding evaluation to further direct negotiations between the parties.[6] The ERP concluded that:

- the PTRM is an appropriate methodology for establishing the price of public lighting services in South Australia
- the appropriate costs for inclusion within the PTRM are: depreciation and return on capital applied to a rolled forward asset base calculated as per the PTRM; corporate income tax; direct operation and maintenance costs; and an allowance for corporate overheads as allocated by the cost allocation method
- the total revenue relating to public lighting services may also include elevation charges and an operating margin included in deriving CLER and Energy Only prices.

Certain issues remained in dispute between the customers and SAPN, and the ERP proposed that the path to settle the dispute was to resolve those issues. These are set out in Appendix 4 of the ERP report, reproduced below.

[4] It is not entirely clear which councils were included in the 66 councils referred to in the Local Government Association's letter. However it is clear from HWL Ebsworth's letter of 2 May 2107 that only 61 councils are now party to the dispute, being those referred to in Attachment A to that letter: see section 2.1 above.

[5] Local Government Association of South Australia letter to AER, 9 December 2013.

[6] Expert Review Panel (Geoff Swier (chair), Luke Woodward and Shaun Dennison), Non-Binding Expert Evaluation: Public Lighting Dispute in South Australia, 9 September 2015.

Figure 2-1 Expert Review Panel 'next steps'

Item	Description
Determine point in time at which an opening AB is established	PLC to consider whether they wish to (a) verify the calculation of the current WDV of public lighting assets, and (b) contend that the ESCOSA 2009 AB value will result in over recovery. If so, then with the appropriate regulatory expert assistance, the Parties should: 1 Use the AER's PTRM to roll forward the asset base based on the SKM 1998 ODRC value and other agreed parameters (depreciation charges, capital additions and reductions); 2 Identify the extent of any difference in the current WDV of PLS assets between a starting AB value using that valuation as compared to the ESCOSA 2009 AB value; 3 Identify precisely the reasons for any difference in the valuation.
Depreciation - asset lives	Calculate depreciation allowance to enable asset costs to be recovered over their economic life using the straight line method. Any dispute as to the proper economic life of SAPN public lighting assets can be resolved through independent expert advice or determination.
Corporate Income tax	Calculate corporate income tax based on including any tax liability arising from the fair value of transferred infrastructure to provide SLUoS (gifted assets), with this amount to be only recovered once. Clarify whether tax liability for gifted assets has been claimed by SAPN from developers.
Corporate overheads costs	SAPN to provide underlying cost allocation information to PLC so that PLC can understand the basis of allocation of overhead costs to PLS, in accordance with the CAM.
Operating margin for setting CLER and EO prices	Parties to consider whether or not to include operating margin for determining CLER and EO prices as part of broader negotiated trade-off. If operating margin for CLER and EO prices is to be included then consider setting this by reference to the average profit that a comparable efficient business may be expected to earn if carrying out similar activities.
Elevation charges	SAPN to consider providing a cogent basis (for example, supported by expert economic or other evidence) that an elevation charge would promote the NEO through improved economic efficiency in provision, or use, of PLS.

Source: Expert Review Panel, Non-binding expert evaluation: public lighting dispute in South Australia, Findings, 9 September 2015

The ERP considered the RAB could be based on the valuation determined by the state regulator, the Essential Services Commission of South Australia (ESCOSA) in 2009, but that it remained open for the PLCs, in negotiations with SAPN, to put forward evidence that using this value will result in an over recovery of costs.[7]

2.3.2 Referral to AER for binding determination

On 2 May 2017, HWL Ebsworth wrote to the AER in relation to the access dispute. HWL Ebsworth stated that it represented 61 local councils listed in the letter, and the Government of South Australia, in respect of the access dispute. In that letter the PLCs requested that the AER determine the access dispute between the PLCs and SAPN under section 128 of the NEL.

The PLCs commissioned a report from Houston Kemp Economists to address certain issues considered by the ERP, specifically:[8]

- the appropriate opening RAB for the dispute period
- the appropriate TAB for the dispute period
- whether elevation charges should be included in the PTRM for the dispute period
- any consequential reduction in corporate overhead as a result of the reduction in any of the above cost components.

Among other things, Houston Kemp considered that SAPN's proposed RAB would result in an over recovery of costs. Houston Kemp estimated an opening RAB value at 1 July 2010 of $21.81 million.[9]

The PLCs made an offer to SAPN reflecting the advice from Houston Kemp,[10] which SAPN rejected. On 2 May 2017 the PLCs requested that we move to finally determine the dispute.[11]

2.4 Scope of access dispute

The access dispute was initiated by the Local Government Association's letter to the AER of 9 December 2013, but the scope of the dispute was narrowed and refined by subsequent dispute resolution processes, in particular the ERP hearing and report.

Following the ERP report, the PLCs made an offer to SAPN as to how to resolve the 'Next Steps' proposed by the ERP (see Figure 2-1 above), based on the report by Houston Kemp. SAPN refused that offer.

The PLCs letter of 2 May 2017 requesting the AER determine the dispute specified, in their view, the outstanding unresolved matters.

The AER set out a proposal for the scope of the access dispute in its letter to the parties on 22 June 2017. In their responses to that letter, the parties agreed to this scope. The AER

7 Expert Review Panel, pp. 13-14.

8 Houston Kemp Economists, Expert Report of Greg Houston, 6 February 2017.

9 Houston Kemp February 2017, pp. 8-11.

10 HWLE Lawyers, Letter to SAPN, 27 February 2017.

11 HWLE Lawyers, letter to AER, 2 May 2017.

confirmed that the scope of the access dispute that it is now determining under Part 10 of the NEL is:

1. The appropriate RAB for the provision of public lighting services during the 2010 to 2015 regulatory control period
2. The applicable TAB for the 2010 to 2015 regulatory control period
3. Whether elevation charges should be included in the PTRM
4. Any consequential fall in corporate overhead as a result of the reduction in any of the above listed cost components.

If we determine that one or more of these PTRM inputs is different than those asserted by SAPN, it will also be necessary for us to determine:

5. The impact this had on the access charges paid for the SLUOS service during the 2010 to 2015 regulatory control (that is, the total excess access charges paid to SAPN over the period)
6. The interest rate that should be used to determine the present value of the total excess charges.

In our letter of 22 June 2017, we stated that we considered that the PLC's offer to settle the dispute of 2 February 2017 was an appropriate basis to define the scope of the dispute. That offer included proposed revised values for the disputed PTRM inputs listed above, and also calculated an amount of excess charges asserted to have been paid as a result, with a present value of those charges calculated using the regulatory WACC determined for SAPN for the 2010-2015 regulatory period. As noted, the parties agreed to the definition of the scope of the dispute in their responses to our 22 June letter.

We discuss the scope of the access dispute, and our role in determining it, in more detail in Chapter 5 on 'Our assessment approach'.

2.5 Determination procedure

2.5.1 Submissions and reply

We wrote to the parties on 22 June 2017, setting out a proposed process for determining the access dispute, and we also invited the parties to comment on that process. The parties made written submissions to the AER regarding the determination process we proposed.[12] On 2 August 2017, we wrote to the parties setting out our decision on the process for determining the access dispute. In that letter we set out a process for submissions, summarised in table 2-1.

[12] HWLE Lawyers, Letter to AER, 6 July 2017; Gilbert and Tobin, Letters to the AER, 6 July 2017 and 12 July 2017.

Table 2-1 Determination process as notified to parties

Process step	Detail	Timing
AER: Arbitration initial letter	Sent	22 June 2017
Parties: Response	Received	6 July 2017
AER: Response and initiation letter	Letter 2 August 2017	2 August 2017
PLCs	Provide ERP report to AER	8 August 2017
SAPN: Submission in response to the Houston Kemp report	SAPN responds to Houston Kemp Report (Limit of 60 pages)	30 August 2017
PLCs: Submissions in reply to SAPN's submissions	PLCs to provide reply submission to SAPN's submission Reply submissions must not raise new issues (Limit of 25 pages)	20 September 2017
SAPN: Submissions in response to public lighting customers' reply submissions	SAPN provides further reply submission to PLC's reply submission Reply submissions must not raise new issues (Limit of 25 pages)	12 October 2017
AER: gather further information required for draft determination	AER considers all submissions and determines whether it requires further information to determine the dispute If necessary, engage and brief independent expert/s AER issues any information requests deemed necessary Advise AER's views on parties' comments on process and merits of any requests for oral hearing/meeting	TBC
AER: draft determination	AER to issue draft determination on access dispute	TBC
Parties: submissions on draft determination	SAPN and PLCs to provide submission on draft determination	Within 15 business days of draft determination
AER: final determination	AER issues final determination	TBC (timeframe likely to be set out in draft determination)

Source: AER letter to parties 2 August 2017

We reserved the right to alter this process if it seemed appropriate. SAPN and the PLC's provided written submissions to us in accordance with the table set out above. We have extended the period for the parties to make submissions on our draft determination from 15 to 20 business days.

2.5.2 Oral hearing

Having considered the parties written submissions, we decided to conduct an oral hearing in an effort to clarify certain issues in the access dispute, in particular concerning the RAB for public lighting services. We notified the parties of this by letter dated 16 March 2018.

Hearings of access disputes under Part 10 of the NEL are to be private, unless the parties agree otherwise (NEL section 137). In our initial correspondence with the parties regarding the procedure for hearing this dispute, the PLCs sought that the hearing of the matter be public. In response SAPN submitted that any oral hearing should be in private, as well as confidential information provided by the parties. SAPN did not otherwise object to the publicity of the hearing.

In response the AER made an order under s 141 of the NEL that restricted the parties from divulging any information obtained as a result of, and during the course of, any oral hearing.

We conducted further correspondence with the parties in April 2018 concerning the issues to be discussed at the oral hearing, and requested the parties to focus their oral submissions on the following:

1. For the purposes of determining the RAB for street lighting services at 2010, can and should the AER consider matters prior to ESCOSA's 2009 determination?
2. What is the nature of ESCOSA's 2009 Determination and its relevance to determining the RAB at 2010?
3. What is the nature of the SAIIR 2000 determination and its relevance in determining the RAB at 2010?
4. If the AER agrees with the PLCs that (i) the 'whole-of-life' depreciation principle is applicable to determining the RAB at 2010, (ii) public lighting revenue in any part of the period between 1998 and 2010 has violated the whole-of-life principle, what determinations ought it make?
5. If the AER determines that it does not have the power to compensate the PLCs in respect of any overpayments made prior to the period when the AER commenced regulating SAPN, (and if the AER agrees with the PLCs on matters described in question 4) how should the PLCs be compensated, and on what basis (bases)?

We conducted an oral hearing in the AER's Melbourne office on Monday, 7 May 2018. Each member of the AER attended the hearing. AER Board member, Mr James Cox, presided at the hearing. The proceedings of the oral hearing were recorded and a copy of the transcript was provided to the parties.

The parties made oral submissions to us on the issues in the access dispute through their legal counsel. The AER Board members questioned the parties on their positions in the access dispute, through their legal counsel.

Each party was given 30 minutes to present their case after which the AER Board asked questions, and at the end each party was given an opportunity to make final closing comments. To ensure each party had sufficient opportunity to present its case, parties were allowed to make a post hearing submission if they wished.

2.5.2.1 Key matters raised at the oral hearing

We have not attempted to summarise the transcript, but have focused on the principal areas of agreement and disagreement between the parties that assisted the AER's decision making as discussed in sections 6-12 of this decision.

A key theme in the oral hearing was that both parties were trying to create certainty, whether by applying their preferred methodology or by interpreting the actions of the previous regulators. Each party points to uncertainty or misunderstandings in each other's case:

1. At the hearings PLC stated that the Houston Kemp methodology for determining the asset value is not a new or novel approach, as it is no different to the 'recovered capital method' (RCM) recently introduced into Part 23 of the National Gas Rules. Their central argument is that SAPN ignores the return on capital previously recovered as made in the SAIIR determination, and the asset valuation needs to account for the period of higher capital recovery.[13]
2. PLC discussed SAPN's claims that information on depreciation prior to 2005 did not exist.[14] SAPN argued that the data does not exist because there was no building block model from 2000 to 2005.[15]
3. PLC noted that the SAIIR determination included a 3 year asset base roll forward and approved year on year depreciation, which was higher than the year-on-year depreciation approved by ESCOSA 2009.[16] [17]
4. SAPN agreed the initial asset value had a 20 year asset life attached to it.[18] SAPN argued that the differentiating feature of the SAIIR determination (when the 20 year asset life was used) compared to the ESCOSA determination is that the latter is an orthodox building block approach.[19] SAPN stated it is 'flawed to take from the SAIIR determination the fact that at that point in time for the year 2000 it was acting on a 20 year assumed asset life.'[20]
5. SAPN criticised the Houston Kemp methodology and pointed to uncertainty in the final asset valuation because of the number and type of assumptions that need to be made.[21]

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13 Transcript of hearing, 7 May 2018, p. 8, line 40.

14 Transcript May 2018, p. 10, line 5-15. As discussed in section 6, SAPN has not substantiated on what basis is provided asset base roll forward calculations commencing in 2004-05 without previous assumptions for depreciation (ESCOSA 2008).

15 Transcript May 2018, p. 55, line 31-33.

16 Transcript May 2018, p. 27, line 45.

17 Transcript May 2018, p. 38, line 38-41.

18 Transcript May 2018, p. 26, line 31.

19 Transcript May 2018, p. 16, line 8.

20 Transcript May 2018, p. 37, line 39-41.

21 Transcript May 2018, pp. 18-21.

6. SAPN raised that if the AER were to move to a third way for determination of the asset value (that is, by not accepting either the PLC's or SAPN's proposed methodology) this may raise procedural fairness issues and the issue of the need to give the parties opportunity to comment.[22]
7. SAPN said it is not appropriate to apply a WACC to any over-recovery because it is not a true cost that is faced by the PLC, and only interest should be charged.[23]

At the hearing the parties agreed:

1. on the criteria that governs the determination[24]
2. that the PTRM is an appropriate methodology for establishing the price of public lighting services
3. the SKM valuation of an ODRC of $37.07 million at 30 June 1998[25]
4. that both SAIIR and ESCOSA made 'fair and reasonable' determinations.[26] To remove doubt: SAIIR reported November 2000 covering period 2000-01 (including an elevation charge of $1 million). ESCOSA reported December 2009 and covered the period 1 July 2005 to 20 June 2009 (including an elevation change of $1.21 million), and
5. on the whole-of-life principle.[27]

2.5.3 Post-hearing submissions

2.5.3.1 SAPN's post oral hearing submission (29 May 2018)

The SAPN submission primarily argued that the Houston Kemp methodology is not an application of the RCM as described in Part 23 of the National Gas Rules, and the AER should not apply the RCM.[28]

SAPN argued that in any case the ESCOSA roll forward is preferable to application of the RCM because it is the most relevant and recent regulatory determination valuing the assets.

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[22] Transcript May 2018, p. 25, line 10-12.

[23] Transcript May 2018, p. 25, line 35-38.

[24] Transcript May 2018, p. 14, line 39-41.

[25] Transcript May 2018, p. 15, line 25.

[26] Transcript May 2018, p. 22, line 30.

[27] Transcript May 2018, p. 42, line 28.

[28] SAPN, Submissions following the oral hearing on 7 May, 29 May 2018, sections C and D. The RCM is described in AER, Financial reporting guidelines for non-scheme pipelines, December 2017.

SAPN accepted that:

- Previous regulatory determinations in relation to the value of the public lighting assets are a relevant matter which must be taken into account by the AER in making its determination.[29]
- Despite this SAPN contended that the ESCOSA determination is the most relevant because it is the most recent.[30] SAPN went on to set out reasons supporting its argument that ESCOSA contemplated its determination of asset value and asset life to be the basis of future determinations.

SAPN acknowledged that the purpose of the ESCOSA[31] determination was a 'fair and reasonable' assessment.

2.5.3.2 PLC's post oral hearing submission (29 May 2018)

PLC addressed SAPN's critique on remaining asset life by noting that the Houston Kemp methodology does not consider standard life but calculates a remaining asset value through capital returns.

PLC restated its position on TAB, and its position that the AER's decision should set out public lighting tariffs for the period 1 July 2010 to 30 June 2015.

Finally PLC reiterated that the discount rate should be WACC as it is consistent with the regulatory practice of using WACC as the time value of money, and in so doing SAPN is neither rewarded or penalised for the over recovery of public lighting revenue.

2.5.4 Draft determination

On 11 February 2019, we issued our draft determination for this access dispute. Consistent with the determination process we had notified to the parties, we invited the parties to make submissions on our draft determination.

2.5.5 Submissions on draft determination

The key documents received following the draft determination are set out in table 2-2 and discussed in the paragraphs which follow.

Table 2-2: Documents received post draft determination

Date received	Document	Description / comment
13 March 2019	SAPN Submission in response to Draft Determination	Includes attachments: Correspondence between Gilbert and Tobin Lawyers 1 March 2019 and ESCOSA CEO 7 March 2019 Incenta Economic Consulting, SA

29 SAPN, May 2018, para 9, p. 3.

30 SAPN, Submissions following the oral hearing on 7 May 2018, 29 May 2018, para 13-14, p. 3.

31 SAPN submission, May 2018, para 17, p. 3.

		Street Lighting – Comment on Draft Determination, March 2019
13 March 2019	SAPN CEO letter to AER Board	
13 March 2019	PLC Submission in response to Draft Access Arrangement	Includes Supplementary Expert Report of Greg Houston, Houston Kemp Economists, 11 March 2019
12 April 2019	ETSA Utilities' submission dated September 2009 to ESCOSA, Public Lighting Charges – Fair and Reasonable Determination	Provided by SAPN in response to AER letter of 10 April 2019
12 April 2019	Two spreadsheets: SAPN RollForward and PTRM model 07022019_Incenta changed version.xlsm.xlsm File PTRM linked to Sapere model.xlsm.xlsm File	Provided by SAPN in response to AER letter of 10 April 2019
15 April 2019	PLC further submission, attaching Further report of Greg Houston on SAPN's submission to the AER's draft decision	Provided by PLC in response to AER letter 10 April 2019
16 April 2019	PLC spreadsheet Implied Asset Life from SAIIR 2000	Provided by PLC in response to SAPN request 16 April 2019
18 April 2019	SAPN Submission in response to PLC further submission dated 15 April 2019	Provided by SAPN in response to AER letter 10 April 2019
18 April 2019	Five attachments to ETSA Utilities' submission to ESCOSA dated September 2009, being: Attachment 2 – ETSA Utilities' Proposal for Settlement Attachment 3 – Average ROA and Depreciation in $Dec08 Attachment 4 – Proposed RAB Roll-forward Model Attachment 6 – Benchmarking representative Attachment 7 – Tax costs of gifted assets	Provided by SAPN to AER in response to AER email 18 April 2019
4 June 2019	Trans-Tasman Group Submission dated September 2009 to ESCOSA, Public Lighting Charges – Fair and Reasonable Determination	Provided by PLC at AER request

2.5.5.1 PLC's submission on the draft determination (13 March 2019)

In response to the draft determination, PLC provided a submission that annexed a supplementary report of Houston Kemp. PLC made no submissions on the draft determination as it related to the elevation charge, TAB, treatment of corporate overheads, the discount rate for over-recovery, or the form of recompense. It confined its submissions to the determination of the RAB.[32]

PLC submitted that the draft determination materially overvalued the opening RAB in two important respects. First, it contended that there was no regulatory precedent for using a roll-forward model (RFM) to determine an opening RAB at the commencement of a regulatory period when the regulated assets had not previously been subject to PTRM-based revenue regulation. Secondly, it contended that the AER had made errors within its application of the RFM - namely, that the AER's modelling treatment of new capex had been done on a basis inconsistent with SAPN's previous pricing model. The consequence of this, PLC submitted, was that the AER had underprovided for a full year's depreciation on new capex and overprovided for a half year real return on that capex.[33]

2.5.5.2 SAPN's submission on the draft determination (13 March 2019)

SAPN provided a submission in response to the draft determination that attached correspondence between SAPN's legal representatives and ESCOSA (described further below) and a supplementary report of Incenta. SAPN accepted the AER's draft determination in relation to corporate overheads and elevation charge,[34] but made submissions concerning the RAB, TAB and discount rate.

As to the RAB, SAPN agreed with the AER that the appropriate method for establishing the opening RAB was a standard roll forward calculation with straight line depreciation, but reiterated its position that applying the ESCOSA roll forward model would best promote the regulatory principles and that departing from that model was unfair.[35] If the AER did adopt its RFM instead of the ESCOSA model, SAPN submitted that, at a minimum, the AER needed to apply a 28-year asset life assumption for post-1998 capital expenditure, to adjust the pre-2005 asset life of existing assets to ensure that it properly reflected the basis on which capital was returned to SAPN in this period, and to make some minor adjustments to correct modelling errors identified by Incenta.[36]

As to the TAB, SAPN agreed with the AER's approach of excluding assets contributed while SAPN was regulated under a pre-tax framework, but reiterated its position that the AER should not set aside the ESCOSA model in favour of a new TAB roll forward calculation.[37]

As to the discount rate, SAPN restated its view that a discount rate at the level of SAPN's WACC would result in a windfall gain to PLC.[38] If the AER did apply that discount rate, SAPN

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32 PLC submission in response to the draft determination, para 3-4, p. 1.

33 PLC submission in response to the draft determination, para 5, pp. 1-2.

34 SAPN submission in response to the draft determination, para 3, p. 2.

35 SAPN submission in response to the draft determination, paras 4-6, pp. 2-3.

36 SAPN submission in response to the draft determination, para 19, p. 5 and para 117, p.21.

37 SAPN submission in response to the draft determination, para 21, p. 5.

38 SAPN submission in response to the draft determination, paras 22-23, p. 6 and para 119, p. 21.

contended that the WACC must be adjusted for actual inflation over the period to which it is applied.[39]

SAPN annexed to its submission correspondence between Gilbert and Tobin and the CEO of ESCOSA, Mr Adam Wilson.[40] Mr Wilson wrote a letter to Gilbert and Tobin dated 7 March 2019 responding to a request for an explanation why ESCOSA adopted a 28 year asset life for public lighting assets in its 'fair and reasonable' determination. Mr Wilson stated that this choice was based on: its analysis of depreciation rates consistent with the outcome of a competitive market; a submission from ESTA Utilities dated 11 September 2009; and a submission from Trans-Tasman Energy Group, on behalf of the PLC, dated September 2009.

SAPN also provided the AER with a letter from its CEO dated 13 March 2019, which summarised SAPN's key concerns with the draft determination. The substance of that letter reflected the content of its submission.

On 13 March 2019 SAPN's CEO wrote to the AER Board raising the possibility of meeting with the Board members to discuss the access dispute. The letter was also emailed directly to individual Board members. The AER wrote to SAPN (20 March 2019) reminding SAPN of the procedures both parties agreed to at the commencement of the dispute. The AER expressed concern with SAPN's approach to the AER Board without informing the PLC, which was contrary to the agreed arbitration procedures, and informed SAPN that such a meeting would be inappropriate. For completeness, the AER letter informed SAPN we saw no need for a further oral hearing in the access dispute. Our correspondence was shared with representatives of PLC.

2.5.5.3 PLC's submission commenting on SAPN's submission on the draft determination (15 April 2019)

By letter dated 20 March 2019, PLC sought an opportunity to respond to three aspects of SAPN's submission on the draft determination that PLC said raised new matters. We allowed PLC to do so, and PLC filed a further report of Houston Kemp responding to those matters.

In response to SAPN's argument that both ESCOSA and SAIIR had considered that a 28-year asset life was appropriate, Houston Kemp opined that SAIIR's November 2000 final report on public street lighting tariffs showed that it applied an asset life assumption closer to an average of 20 years.[41]

Responding to SAPN's contention that it was not reasonable to apply a discount rate at the level of SAPN's regulatory WACC, Houston Kemp opined that SAPN's alternative proposed discount rates would create a strong incentive for network service providers to overcharge for negotiated services and to prolong or delay the process of correcting any over-pricing.[42]

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39 SAPN submission in response to the draft determination, para 115, p. 20.

40 SAPN submission in response to the draft determination, Attachment A

41 Further report of Houston Kemp, 15 April 2019, p. 2.

42 Further report of Houston Kemp, 15 April 2019, p. 4.

Finally, Houston Kemp agreed with SAPN's contention that a discount rate applied at the level of SAPN's WACC should be adjusted for actual inflation.[43]

2.5.5.4 SAPN's submission commenting on PLC's submission dated 15 April 2019 (18 April 2019)

We allowed SAPN the opportunity to respond to PLC's submission dated 15 April 2019.

In its submission in response, SAPN argued that Houston Kemp's analysis that SAIIR had not applied a 28-year asset life to capital expenditure undertaken between 1 July 1998 and 30 June 2001 was 'implausible'; revealed the danger of seeking to draw inferences from particular calculations presented in the SAIIR report, given the high-level and limited nature of the SAIIR analysis; and failed to address the statements in the SAIIR report that a 28-year asset life should be applied to new capital expenditure.[44] It contended that an application of the ESCOSA methodology would avoid any need to draw inferences from the SAIIR analysis.[45]

As to the appropriate discount rate, SAPN reiterated its position that well-established legal principles supported the proposition that the discount rate should restore customers to the position they would have been in but for any overpayment, such that the rate should be no higher than the PLC cost of borrowing.[46] It also disagreed with the Houston Kemp conclusions concerning the threats to efficiency and incentives to overcharge customers or prolong disputes that Houston Kemp said would arise from SAPN's proposed discount rates, and contended that PLC's proposed discount rate would itself create perverse incentives as it would grant PLC a 'larger windfall gain the longer the dispute goes on'.[47]

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43 Further report of Houston Kemp, 15 April 2019, p. 5.

44 SAPN submission in response to the PLC further submission dated 15 April 2019, 18 April 2019, paras 4, 8-11, 14, pp. 2-4.

45 SAPN submission in response to the PLC further submission dated 15 April 2019, 18 April 2019, para 13, p. 3.

46 SAPN submission in response to the PLC further submission dated 15 April 2019, 18 April 2019, paras 5, 16, 24-26, pp. 2, 4-5.

47 SAPN submission in response to the PLC further submission dated 15 April 2019, 18 April 2019, paras 6, 18-21, pp. 2, 4-5.

3 Regulation of public lighting

This section looks at the two inquiries that the two parties have referred to extensively, then outlines the form of economic regulation under the AER during the dispute period.

3.1 South Australian Independent Industry Regulator

In 2000 SAIIR conducted an inquiry into public lighting tariffs.[48] SAIIR was directed to conduct the inquiry by the SA Treasurer under Part 7 of the Independent Industry Regulator Act 1999 (South Australia).

At the time of the review, public lighting tariffs were regulated under the Electricity Pricing Order 1999 (South Australia)(EPO).[49] The EPO set the maximum retail tariffs for public lighting that could be charged by AGL South Australia (the state's then monopoly electricity retailer) for the period until January 2003. It included a considerable number of individual tariffs - for example the EPO schedule listed 14 separate tariffs for standard public lighting services, ranging from $6.05 per month to $23.07 per month according to type of light and wattage.[50]

AGL's retail tariffs were 'bundled', incorporating charges for transmission, distribution, and energy in addition to retail services. The 'distribution' service component was supplied to AGL by ETSA Utilities, and was the subject of the SLUOS charges.[51] SAIIR's inquiry focussed on ETSA Utilities' street lighting charges because, under the EPO, the other tariff components could not be altered.[52] SAIIR noted that the SLUOS component accounted for around 60 percent of the retail tariff.[53] Unlike the other tariff components, ETSA Utilities' charges were subject to a form of regulation whereby charges were required to be 'fair and reasonable'. The EPO clause 3.1 provided:

> 3.1(b) ETSA Utilities must charge for Excluded Distribution Services on a fair and reasonable basis which is consistent with:
>
> (i) The Distribution Code (where applicable); and
>
> (ii) Any other applicable guidelines published by the regulator
>
> and in the event of a dispute the Regulator will subject to clause 3.1(c) determine whether an amount proposed to be charged by ETSA Utilities in respect of an excluded distribution service complies with this clause 3.1(b).
>
> 3.1(c) The regulator must, in considering whether charges for excluded distribution services described in paragraph B4 of the Distribution Services Schedule are fair and reasonable, have regard to the principle set out in section 35A(2) of the Act[54]

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48 SAIIR, Final Report - Public Street Lighting Tariffs, November 2000.

49 Electricity Pricing Order 11 October 1999, made by the SA Treasurer pursuant to section 35B of the Electricity Act 1996 (South Australia).

50 Electricity Pricing Order 1999, Schedule 4C.

51 SAIIR 2000, p. 3.

52 SAIIR 2000, p. 5.

53 SAIIR 2000, p. 49.

54 SAIIR 2000, p. 4.This required SAIIR to have regard to the principles of state-wide pricing for small customers. In this regard, SAIIR stated it would not for the purposes of its inquiry recommend the removal of any cross subsidy that may apply in the provision of street lighting services.

SAIIR approached its task by estimating the efficient costs of providing the services for the year 2000/01. SAIIR considered public lighting tariffs would be 'fair and reasonable' if they recovered no more than the efficient costs of providing street lighting services including any incentive payments that promote socially desirable outcomes.[55] SAIIR conducted benchmarking exercises to compare street lighting costs in South Australia to a sample of electricity distributors from other states, and commissioned a study by the CSIRO of the number of outages affecting ETSA Utilities' street lights.[56]

To estimate the overall cost of providing public lighting services, SAIIR used a methodology incorporating the following assumptions:

- Capital charges were calculated using the rate of return specified in the EPO,[57] and the written down asset value proposed by ETSA Utilities of $35.78 million at 30 June 2001. This provided a return on assets of $3.05 million and a depreciation amount of $3.96 million in 2000/01.
- The written down asset value proposed by ETSA Utilities (and accepted by SAIIR as the basis for calculating 'fair and reasonable' capital charges) was based on a valuation of the assets as at 1 July 1998 by Sinclair Knight Mertz (SKM), rolled-forward using straight line depreciation and an assumed useful life of 20 years.[58] ETSA Utilities' roll-forward model includes written down asset values and depreciation amounts for the years 1998/99, 1999/00 and 2000/01.

For operating and maintenance costs, SAIIR assessed ETSA Utilities' actual repair and maintenance costs against a benchmarking study conducted by SKM.[59] While ETSA Utilities identified its costs as $4.2 million for 2000/01, SAIIR concluded that the allowable cost recovery for repair and maintenance should be in the order of $3.85 million.[60] With the addition of other operational costs and overheads (such as asset replacement, inspection, fault identification, technical standards and administration), SAIIR concluded that total operation and maintenance costs of $4.40 million were 'fair and reasonable'.[61]

SAIIR also allowed for a 'pole attachment' or 'elevation' component of the public lighting cost base.[62] SAIIR calculated this as a residual of total retail revenue, less all other charges (retail costs, distribution and transmission charges, return on assets, depreciation and operating and maintenance).

SAIIR concluded that ETSA Utilities' then projected street lighting revenue of $18.4 million for 2000/01 'provides a fair and reasonable return to ETSA Utilities and AGL SA'. This was

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55 SAIIR 2000, pp. iii, ix. The terms of reference directed SAIIR to take into account the costs of providing the service and complying with regulatory obligations and 'the return on assets used to provide the street lighting services' (among other considerations).

56 SAIIR 2000, pp. 7-10.

57 Weighted Average Cost of Capital (WACC) used in the Electricity Pricing Order was 8.26% pre-tax, real for the initial regulatory period (2000-2005: SAIIR 2000, p. 23.

58 SKM, ETSA Utilities Asset Valuation September 1999 Final; SAIIR 2000, pp. 25-27. ETSA Utilities' asset roll-forward table (reported in SAIIR 2000, Box 3.1, p. 26) is reproduced in section 6.7.2 below.

59 SAIIR commissioned SKM to conduct an interstate benchmarking study of tariffs and costs. SAIIR acknowledged the limitations of the benchmarking exercise, stating they provided a broad understanding of the reasonable range of efficient expenditure and as such provided guidance only: SAIIR 2000, p. 18.

60 SAIIR 2000, p. 29.

61 SAIIR 2000, p. 41.

62 SAIIR 2000, p. 35.

based on a 'fair and reasonable' SLUOS charge of $12.4 million, which included an implied elevation charge of approximately $1 million.[63] SAIIR also stated:[64]

> SAIIR believes that ETSA Utilities should be seeking ongoing cost reductions in the provision of street lighting services over time, and sharing these gains with councils or continuing to improve the level of service provided.

3.2 Essential Services Commission of South Australia

From 1 July 2005 to 30 June 2010 public lighting tariffs were regulated under an Electricity Distribution Price Determination (EDPD), made by ESCOSA under the *Essential Services Commission Act 2002* (South Australia).[65]

The EDPD required that public lighting charges be 'fair and reasonable.' Under the EDPD, ESCOSA had no role in examining or approving public lighting charges unless a dispute was notified.[66] The relevant part of the EDPD is as follows:

> 2.1.2 ETSA Utilities must charge for excluded services on a fair and reasonable basis which is consistent with:
>
> (a) the Electricity Distribution Code (where applicable); and
>
> (b) any other applicable industry codes, rules or guidelines published by the Commission.
>
> 2.1.3 In the event of a dispute in relation to the amount of a charge for an excluded service, the Commission will determine whether the amount proposed to be charged by ETSA Utilities in respect of that excluded service complies with clause 2.1.2 having regard to:
>
> (a) cost reflectivity;
>
> (b) overall profitability in relation to excluded services; and
>
> (c) the degree and effectiveness of market competition.

Thus, when deciding on the fairness and reasonableness of charges, ESCOSA had to consider cost-reflectiveness, overall profitability and the degree and effectiveness of market competition.[67] An ESCOSA guidance note stated that a 'fair and reasonable' price would allow ETSA Utilities to recover prudent expenditure, including a fair and reasonable profit margin.[68]

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63 SAIIR 2000, p. 49.

64 SAIIR 2000, p. 50.

65 ESCOSA, 2005-2010 Electricity Distribution Price Determination, Part B – Price Determination, April 2005 made under the Essential Services Commission Act 2002 (South Australia).

66 ESCOSA, ETSA Utilities Lighting Excluded Services Charges, Fair and Reasonable Determination, December 2009, p. 5.

67 The Electricity Distribution Price Determination provided:

2.1.2 ETSA Utilities must charge for excluded service on a fair and reasonable basis which is consistent with:

(a) the Electricity Distribution Code (where applicable); and

(b) any other applicable industry codes, rules or guidelines published by the Commission.

2.1.3 In the event of a dispute in relation to the amount of a charge for an excluded service the Commission will determine whether the amount proposed to be charged by ETSA Utilities in respect of that excluded service complies with clause 2.1.2 having regard to:

(a) cost reflectivity;

(b) overall profitability in relation to excluded services; and

(c) the degree and effectiveness of market competition.

68 ESCOSA, Electricity Industry Guideline No. 14, Excluded Services Regulation – Distribution.

In December 2007 a dispute was notified over ETSA Utilities' public lighting charges.[69] ESCOSA commenced an inquiry and, in December 2008, issued a Statement of Issues to the parties setting out its views on the relevant issues and directed them to pursue further negotiations. This included ESCOSA's preliminary view on the revenue elements for the year 2007/08 which comprise a fair and reasonable basis for setting charges.[70] ESCOSA concluded that ETSA Utilities' actual revenue for 2007/08 exceeded the 'fair and reasonable' revenues by an amount in the order of $1.0 million to $1.4 million.[71]

However a commercial settlement was not reached and in December 2009, ESCOSA made its determination.[72] ESCOSA concluded that ETSA Utilities' average annual revenue from public lighting services from 1 July 2005 to 31 December 2009 was in keeping with the costs of providing the services, and accordingly that ETSA Utilities' public lighting charges were 'fair and reasonable'.

ESCOSA estimated the costs using a form of building block methodology, based on asset related costs (return on capital and return of capital), operating and maintenance costs, and elevation charges. The individual cost components were derived primarily from information provided by ETSA Utilities.

To calculate the asset related cost components, ESCOSA adopted an asset value based on the SKM 1998 valuation, which it rolled-forward to reflect capital expenditure, disposals, contributions, inflation and depreciation.

ESCOSA's approach to depreciation was as follows:

- ESCOSA considered the depreciation rate should be between 8 and 12 percent of the asset base per annum, which would produce a price path broadly consistent with the outcome of a competitive market.
- ETSA Utilities reported depreciation charge of $5.70 million for the year 2007/2008 pointing to a 20 percent depreciation rate. ESCOSA's 2008 Statement of Issues found this depreciation rate would not comply with the above principle.[73]
- ETSA Utilities then revised its depreciation schedule so as to use an average asset life of 28 years starting with the SKM valuation. This resulted in a depreciation rate within the recommended range.
- ESCOSA accepted ETSA Utilities' revised depreciation rate as an appropriate basis for a 'fair and reasonable' public lighting charge.[74]

ESCOSA calculated the capital charges using a rate of return determined in accordance with the EDPD (7.13 percent pre-tax real).

ESCOSA determined that, despite the variability in operating and maintenance expenditure associated with public lighting, $5.1 million per annum over the 2005-2009 period formed a

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69 ESCOSA Fair and Reasonable Determination 2009, p. 8. ESCOSA examined charges for SLUOS and CLER services, whereas our focus is SLUOS. However nothing significant comes from this distinction.

70 ESCOSA, ETSA Utilities Public Lighting Service Charge Statement of Issues, September 2008, para 202, p. 39.

71 ESCOSA Statement of Issues 2008, table 6.1, p. 39.

72 ESCOSA Fair and Reasonable Determination 2009, p. 37.

73 ESCOSA Statement of Issues 2008, p. 20.

74 ESCOSA Fair and Reasonable Determination 2009, pp. 19-20.

‘fair and reasonable’ basis for setting public lighting charges. It also considered that directly incurred costs formed a reasonable basis for allocating overhead costs, estimating that 55 percent of total excluded services allocated costs relate to public lighting. Applying this share to overhead costs, it determined that $1.6 million per annum was ‘fair and reasonable’.

ESCOSA accepted the existing elevation charge of $10.60 per light per annum to be ‘fair and reasonable’, given it was consistent with the elevation charge applied in the 2000 SAIIR determination. This equated to an elevation charge of $1.21 million per annum.

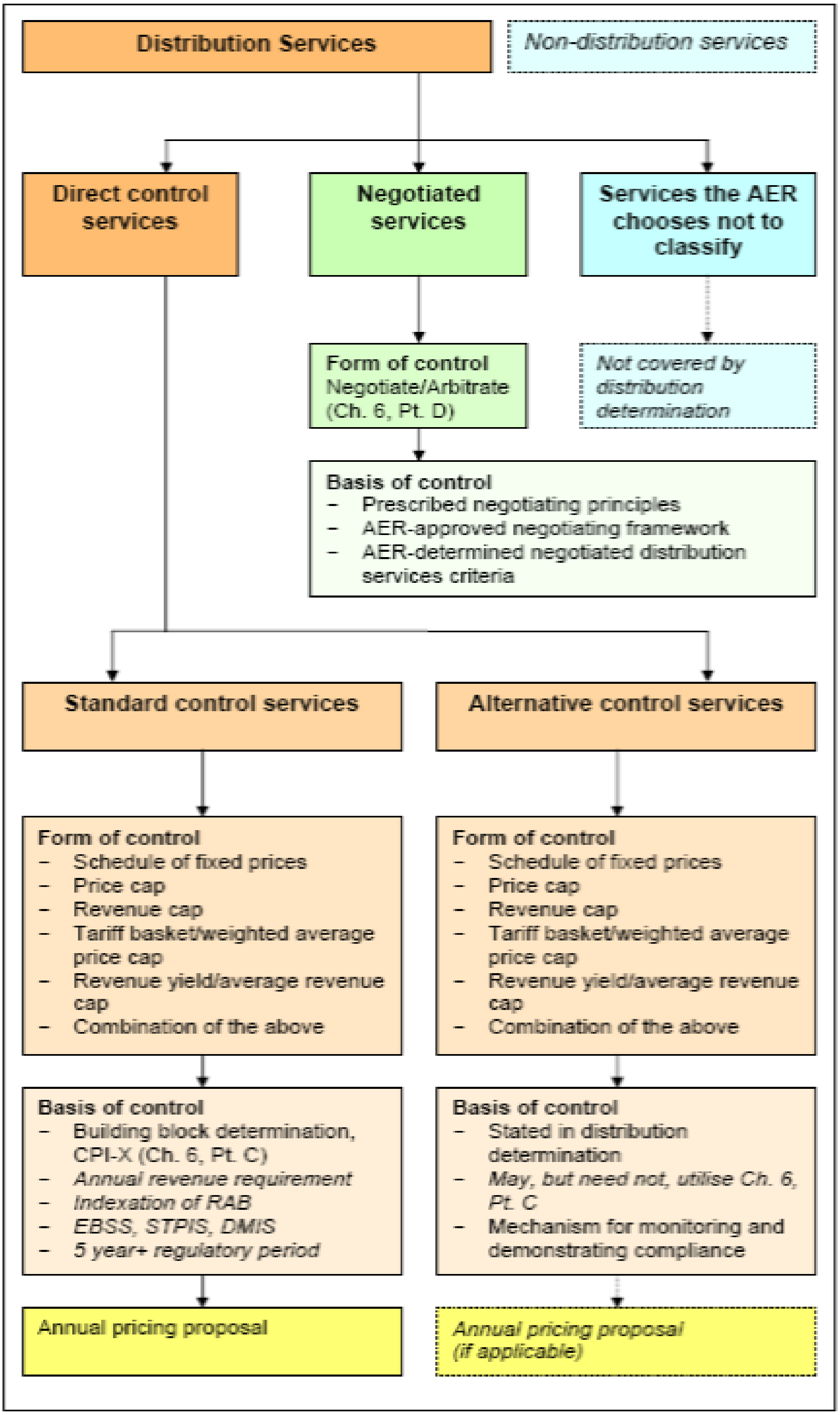
3.3 Australian Energy Regulator

On 1 July 2010 we assumed responsibility for the economic regulation of electricity distribution services in South Australia, including public lighting services.

Under chapter 6 of the NER, we were required to classify the distribution services provided by ETSA Utilities and make a distribution determination for the 2010-2015 regulatory control period. Figure 3-1 sets out the scheme of classification under the NER and the form of regulation applicable to each service classification. Figure 3-1 illustrates that service classification determines two key aspects of the distribution determination:

- whether the service should be under a direct price or revenue control, a 'negotiate-arbitrate' framework, or no price or revenue control, and
- whether the costs of the service should be recovered through distribution use of system tariffs paid by all or most customers, or through separate tariffs paid by the individual customers requesting the services.

Figure 3-1 Classification of services under National Electricity Rules



In classifying ETSA Utilities' services, the NER required us to have regard to a set of factors relating to the market landscape.[75] We were also required to act consistently with the previous regulatory approach unless a different classification is clearly more appropriate.[76]

Applying these principles to ETSA Utilities' services, we determined that:

- ETSA Utilities' prescribed distribution services would be classified as direct control services under the NER, and
- ETSA Utilities' excluded services - including public lighting services[77] - should be classified as negotiated services.[78]

ETSA Utilities' regulatory proposal included an indicative price list for public lighting services. In making our determination we emphasised we were not providing an ex-ante assessment or approval of the prices on ETSA Utilities' price list.[79] The assessment framework in the NEL/NER that the AER must apply in the event of a dispute is discussed in the next section (Section 4).

75 These factors (the 'form of regulation factors') are set out in NEL, s. 2F.

76 NER, ss. 6.2.1(d) and 6.2.2(d).

77 To be clear, SLUOS, CLER and EO services were all classified as negotiated services.

78 AER, Final Decision - South Australia distribution determination 2010-11 to 2014-15, May 2010, p. 283.

79 AER, Final Decision - South Australia distribution determination 2010-11 to 2014-15, May 2010, p. 14

4 The legal framework

4.1 General

In this matter the AER must determine an access dispute in accordance with Part 10 of the NEL.[80] This function is enlivened when a network service user (or prospective network service user) of a negotiated distribution service notifies the AER that an access dispute exists regarding that service.

The Local Government Association initiated this process by letter dated 9 December 2013, by which it notified the AER of its dispute with SAPN regarding the price charged for public lighting services. The dispute notified is an 'access dispute' to which Part 10 of the NEL applies as:

- Public lighting services are 'negotiated distribution services'[81]
- A dispute plainly exists in the sense that the parties are unable to agree - this is stated in PLC's dispute notice,[82] and is not contested
- The dispute is between a Distribution Network Service Provider and Service Applicants (within the meaning of the NER) about access charges
- The dispute is about an aspect of access to an electricity network service that is both, specified by the NER (clause 6.22.1(a)) to be an aspect to which Part 10 applies,[83] and provided by means of or in connection with a distribution system.

In accordance with section 129 of the NEL the AER referred the parties to alternative dispute resolution, leading to mediation by the ERP as discussed above in sections 2.2.2 and 2.2.3. That process further narrowed the nature and scope of the access dispute, as set out in section 2.2.3.

An access dispute once notified must be determined by the AER unless it is withdrawn or we decide it should be terminated.[84] Neither of those things has occurred. The parties to a dispute must comply with the AER's determination.[85]

4.2 Decision-making principles

In making our determination, we must:

- perform our functions and powers in a manner that will or is likely to contribute to the achievement of the National Electricity Objective (NEO)

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80 NEL ss. 15(1)(f)), 128.

81 NEL s. 125. Street lighting was classified as a negotiated distribution service in the AER's Final Decision: South Australia Distribution Determination 2010-11 to 2014-15, May 2010, so a dispute about terms and conditions of access (including prices/charges) is an 'access dispute' under the NEL. Street lighting services are provided 'in connection with' a distribution service - see Logan J in Ergon Energy Corporation v AER [2012] FCA 393, which held that public lighting in Queensland was a regulated distribution service because it was provided 'in connection with' the distribution system

82 PLCs (HWLE Lawyers) letter to AER dated 3 May 2017.

83 NEL. s. 2A.

84 NEL s. 131.

85 NEL s. 136.

- take into account the Revenue and Pricing Principles (RPPs)
- apply the Negotiated Distribution Service Criteria (NDSC)
- apply the relevant provisions of Chapter 6 of the NER, in particular Part L
- consider any other matters we consider relevant.

In these Reasons we refer to these requirements collectively as our obligation to give effect to 'the regulatory principles'.

4.2.1 National Electricity Objective

We must exercise our economic regulatory functions and powers (including our powers and functions in relation to an access dispute) in a manner that will or is likely to contribute to the achievement of the NEO,[86] which is stated in section 7 of the NEL.[87]

National electricity objective

The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interest 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.

4.2.2 Revenue and Pricing Principles

In addition, when making an access determination relating to prices, we must take into account the RPPs,[88] which are set out below:[89]

RPP 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.

RPP 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.

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86 NEL s. 16(1)(a).

87 The definition of 'AER economic regulatory functions and powers' includes a function or power performed or exercised by the AER under the NEL or the NER that relates to an access determination: NEL s. 2.

88 NEL s. 16(2)(a)(ii). In these Reasons the expression 'RPP 2' refers to the principle in s. 7A(ii); 'RPP 3' refers to the principle in s. 7A(3), and so on.

89 NEL s. 7A. The RPPs are modified in the context of an access determination by NEL s. 16(3) which provides that for the purposes of s 16(2)(a)(ii), references to a ‘direct control network service’ must be read as a reference to an ‘electricity network service’.

RPP 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.

RPP 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.

RPP 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.

RPP 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.

4.2.3 Negotiated Distribution Service Criteria

In making our determination, we also need to apply the NDSC, which in turn 'must reflect' the Negotiated Distribution Services Principles.[90] The applicable NDSCs are set out in the AER's Final Decision: South Australia Distribution Determination 2010-11 to 2014-15, May 2010as follows:[91]

National electricity objective

NDSC 1: The terms and conditions of access, including the price and any access charges, should promote the achievement of the national electricity objective.

Terms and conditions of access

NDSC 2: The terms and conditions of access must be fair and reasonable consistent with the safe and reliable operation of the power system in accordance with the NER.

NDSC 3: The terms and conditions of access for a negotiated distribution service (including in particular, any exclusions and limitations of liability and indemnities) must not be unreasonably onerous taking into account the allocation of risk between a distribution network service provider (DNSP) and any other party, the price for the negotiated distribution service and the costs to a DNSP of providing the negotiated distribution service

NDSC 4: The terms and conditions of access for a negotiated distribution service must take into account the need for the service to be provided in a manner that does not adversely affect the safe and reliable operation of the power system in accordance with the NER

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90 NER 6.22.2(c)(1). The Negotiated Distribution Service Criteria must give effect to and be consistent with the Negotiated Distribution Services Principles set out in NER 6.7.1 - see NER: 6.7.4(b).

91 AER, Final Decision: South Australia Distribution Determination 2010-11 to 2014-15, May 2010, p 289 (Appendix C: Negotiated Distribution Service Criteria); AER, Final Decision: SAPN Determination 2015-2016 to 2019-2020, October 2015 (Attachment 17 - Negotiated Services Framework and Criteria, pp 17-9 to 17-11).

Although the 2010-15 NDSCs use 'must reflect' whereas the 2015-20 NDSCs use 'should be based on', we consider nothing turns on this distinction.

Price of services

NDSC 5: The price for a negotiated distribution service should be based on the costs that a DNSP has incurred or incurs in providing that service, and must be determined in accordance with the principles and policies set out in the DNSP's Cost Allocation Method.

NDSC 6: Subject to criteria 7 and 8, the price for a negotiated distribution service must be at least equal to the cost that would be avoided by not providing that service but no more than the cost of providing it on a stand-alone basis.

NDSC 7: If a negotiated distribution service is a shared distribution service that:

exceeds any network performance requirements which it is required to meet under any relevant electricity legislation: or

exceeds the network performance requirements set out in schedules 5.1a and 5.1 of the NER,

then the difference between the price for that service and the price for the shared distribution service which meets network performance requirements must reflect a DNSP's incremental cost of providing that service (as appropriate).

NDSC 8: If a negotiated distribution service is the provision of a shared distribution service that does not meet or exceed the network performance requirements, the difference between the price for that service and the price for the shared distribution service which meets, but does not exceed, the network performance requirements, should reflect the cost a DNSP would avoid by not providing that service (as appropriate).

NDSC 9: The price for a negotiated distribution service must be the same for all Distribution Network Users unless there is a material difference in the costs of providing the negotiated distribution service to different Distribution Network Users or classes of Distribution Network Users.

NDSC 10: The price for a negotiated distribution service must be subject to adjustment over time to the extent that the assets used to provide that service are subsequently used to provide services to another person, in which case such adjustment must reflect the extent to which the costs of that asset are being recovered through charges to that other person.

NDSC 11: The price for a negotiated distribution service must be such as to enable a DNSP to recover the efficient costs of complying with all regulatory obligations or requirements associated with the provision of the negotiated service.

Access charges

NDSC 12: Any charges must be based on costs reasonably incurred by a DNSP in providing distribution network user access, and, in the case of compensation referred to in clauses 5.5(f)(4)(ii) and (iii) of the NER, on the revenue that is likely to be forgone and the costs that are likely to be incurred by a person referred to in those provisions where an event referred to in those provisions occurs (as appropriate).

NDSC 13: Any charges must be based on costs reasonably incurred by a DNSP in providing transmission network user access to services deemed to be negotiated distribution services by clause 6.24.2(c) of the NER, and, in the case of compensation referred to in clauses 5.4A(h) to (j) of the NER, on the revenue that is likely to be foregone and the costs that are likely to be incurred by a person referred to in those provisions where an event referred to in those provisions occurs (as appropriate).

In addition, we must have regard to the negotiating framework for negotiated distribution services which is set out in the applicable price determination (NER cl. 6.22.2(c)). The framework sets out detailed negotiating procedures, and provides for dispute resolution by the AER in accordance with Part 10 of the NEL and Part L of Chapter 6 of the NER.[92]

[92] AER, Final Decision, South Australia distribution determination 2010-11 to 2014-15, May 2010, Appendix D.

4.2.4 Chapter 6 of the NER

In determining access disputes, we must apply Part L of Chapter 6 of the NER. Part L comprises rule 6.22, which relevantly provides as follows.

6.22.2 Determination of dispute

…

(c) In determining an access dispute about terms and conditions of access to a negotiated distribution service, the AER must apply:

(1) in relation to price (including access charges), the Negotiated Distribution Service Criteria that are applicable to the dispute in accordance with the relevant distribution determination; and

(2) in relation to other terms and conditions, the Negotiated Distribution Service Criteria that are applicable to the dispute and Chapters 4, 5, this Chapter 6 and Chapter 7 of the Rules; and

(3) in relation to all terms and conditions of access (including price) the decisions of AEMO or the AER where those decisions relate to those terms and conditions and are made under Chapters 4, 5, this Chapter 6 and Chapter 7 of the Rules;

and must have regard:

(4) to the relevant negotiating framework prepared by the Distribution Network Service Provider and approved by the AER.

(d) In determining an access dispute about the terms and conditions of access to a negotiated distribution service, the AER may:

(1) have regard to other matters the AER considers relevant; and

(2) hear evidence or receive submissions from AEMO and Distribution Network Users notified and consulted under the Distribution Network Service Provider's negotiating framework.

(e) In determining an access dispute about access charges, or involving access charges, the AER must give effect to the following principle:

Access charges should be based on the costs reasonably incurred by the Distribution Network Service Provider in providing distribution network user access and, where they consist of compensation referred to in clause 5.5(f)(4)(ii) and (iii), on the revenue that is likely to be foregone and the costs that are likely to be incurred by a person referred to in those provisions where an event referred to in those provisions occurs.

5 Our assessment approach

In our letter to the parties of 22 June 2017, we proposed that the scope of the access dispute be expressed as follows:

Whether the charges for public lighting services in the dispute period were excessive by reason of the charges:[93]

1. *incorporating an opening RAB that was too high*
2. *incorporating an opening TAB that was too low*
3. *including corporate overhead charges that were not justified.*
4. *including an elevation charge that is not justified.*[94]

If any of the above matters are established, we must also determine:[95]

5. *the quantum by which access charges were excessive as a result*
6. *the appropriate means to calculate the net present value of those excess charges for the purpose of correcting any overpayment.*

As we explained in section 2.4 above, the parties did not object to this definition when invited to comment.

In assessing this access dispute, we have considered whether the opening RAB, the opening TAB and the corporate overheads were calculated in accordance with a methodology which gives effect to the regulatory principles, and whether the inclusion of an elevation charge gives effect to those principles.

That is, we have assessed whether the calculation or inclusion of those respective cost inputs contributes to the achievement of the NEO, applies the relevant NDSCs and rule 6.22 of the NER, and takes into account the relevant RPPs. If we determine that the calculation or application of a cost input does not give effect to the regulatory principles, we have assessed what alternative input should be applied that does give effect to those principles.

In making these assessments, we have had regard to the submissions of the parties (which, in some cases, have narrowed the scope of the matters in dispute). Further, the scope of the dispute put forward by the parties requires the AER to exercise its judgment, and we have done so in the broader regulatory context, having regard to our experience and expertise in energy regulation. If we determine that it is necessary to adjust the cost inputs to give effect to the regulatory principles, we must determine the quantum by which access charges were excessive. Our approach in doing so is to estimate the efficient costs incurred by SAPN in providing public lighting services in the dispute period, and compare this with SAPN's public

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93 See AER letter to parties 22 June 2017 section 3, p. 3; SAPN (Gilbert and Tobin) Response 6 July 2017 pp. 1-2 'Scope of the access dispute'; PLC (HWLE Lawyers) Response 6 July 2017 'If not specifically mentioned, the PLCs are otherwise content with what has been proposed'; AER letter to parties 2 August 2017, p. 6 'The scope of the Access Dispute is defined in section 3 of the Initial Process letter'.

94 The elevation charge was resolved prior to our determination - see section 7 below.

95 The last two matters are not expressly mentioned in section 3 of the letter but arise by necessary implication. Further, the AER sought submissions on how to calculate the NPV, in particular whether Houston Kemp's approach of using the regulatory WACC is appropriate. Hence this is clearly a matter of contention between the parties.

lighting revenues. An excess of reported revenues over efficient costs would support a conclusion that access charges in the period were excessive.

To determine the quantum of any excess charges, we have used the PTRM to estimate SAPN's total efficient public lighting costs for the dispute period. For the cost inputs which are disputed, we have used inputs we have assessed will give effect to the regulatory principles. For the inputs not in dispute, we have used values provided by SAPN. This is in keeping with the method SAPN says it has used since 2012 to cross-check the reasonableness of its public lighting charges.[96] Moreover, the parties have agreed the PTRM is an appropriate basis for assessing efficient costs for the purpose of determining the level of charges in this dispute.[97]

The PTRM is a methodology, encompassed in a series of spreadsheets, for calculating a network service provider's annual revenue requirement for each year of a regulatory control period. It is an example of a 'building block' approach, wherein the total allowed revenues for a regulated service or entity is built up by building up the constituent cost components.

While the AER's PTRM relates specifically to building block determinations for standard control services (i.e. it does not as a matter of law apply to negotiated services), the parties have agreed to use the AER's PTRM to estimate SAPN's total costs, and by extension the appropriate level of revenues, for the purposes of this dispute.[98]

We have sought to give effect to the NEO and other regulatory principles in deciding what interest rate should be applied to calculate the present value of any excess charges.

We engaged Sapere Research Group to provide modelling reports related to the access dispute. We have had regard to Sapere's reports primarily to the extent we have made use of the modelling calculations it has performed in accordance with our instructions. This work has primarily consisted of performing calculations applying the RFM and the PTRM to given data sets, and is expressly referred to in this determination. Sapere has also expressed views on additional matters in its reports, such as the application of the regulatory principles.

96 SAPN used the PTRM for the 2010-15 period, whereas we are using the version of the PTRM which has applied since January 2015.

97 SAPN, Submission, 30 August 2017, p. 6, para 21: 'There seems now to be no issues that charges for SLUOS should reflect the economic cost of service delivery, and that this economic cost is properly calculated by the AER's PTRM'.

PLC (HWLE Lawyers) letter to AER 2 May 2017; Houston Kemp February 2017, p. 7; SAPN (Gilbert and Tobin) letter to AER 6 July 2017; AER letter to parties 22 June 2017; Transcript May 2018, line 7, p. 29, line 40, p. 42 (PLCs).

98 SAPN submission, August 2017, para 21, p. 6; Houston Kemp February 2017, p. 7; PLC, Reply submission, September 2017, para 4, p. 1; , PLC letter 2 May 2017; Gilbert and Tobin letter 6 July 2017; AER letter 22 June 2017.

6 Regulatory Asset Base

The RAB represents the value of the capital assets used to provide a regulated service. It is an input to the PTRM, where it is used to calculate capital charges consisting of a return on assets and depreciation (also known as a return of capital) over a given asset life. A higher RAB supports higher capital charges, and so supports higher tariffs for the regulated service.

This section sets out our decision and reasons on the value to be attributed to SAPN's public lighting assets at 1 July 2010, the start of the dispute period ('the opening RAB'), and the value to be attributed to those assets each year within the dispute period.

6.1 Decision

We determine the RAB value for the public lighting assets at the commencement of the dispute period is $34.6 million. The opening RAB and the RAB values for the dispute period are set out in table 6-1.

Table 6-1 AER decision on RAB values ($ million, nominal).

	2010/11	2011/12	2012/13	2013/14	2014/15
Opening RAB	34.79	35.51	36.53	37.48	37.78
Closing RAB	35.51	36.53	37.48	37.78	38.76

To establish the opening RAB at 1 July 2010 we have taken as our starting point the SKM valuation as at 30 June 1998,[99] and we have rolled this forward using the AER's asset roll-forward model for electricity distribution network service providers (RFM).

To apply the RFM, it is necessary for us to make an assumption about the average total economic life and remaining useful life of the assets. We have made the following assumptions:

- For the period 1 July 1998 to 30 June 2005, the assets had an average total economic life of 20 years. The assets had an average age of 9 years at the time of the SKM valuation, and therefore had an average remaining useful life of 11 years at 1 July 1998
- From 1 July 2005 the average total economic life of the assets was increased to 28 years. The remaining undepreciated value is depreciated accordingly from that date.

The RAB values for the balance of the dispute period (i.e. from 1 July 2011 to 30 June 2015) are calculated using the PTRM based on the asset life assumptions set out above.

[99] SKM, ETSA Utilities Asset Valuation, September 1999.

Our reasons are explained below. We engaged Sapere to calculate the opening RAB and yearly RAB values for this dispute. Sapere's reports and workbook are provided to the parties with this draft determination.[100]

6.2 Outline of this Chapter

1. We explain how the regulatory principles apply to the opening RAB.
2. We then provide a summary of the parties' submissions on the matters in dispute.
3. We then explain why we consider the RFM is the most appropriate method to establish the opening RAB - in short, it is the standard method used to establish an opening RAB for the PTRM, and meets the regulatory principles in the NEL and the NER.
4. To apply the RFM it is necessary (a) to decide upon a starting valuation and (b) make assumptions about the useful life of the assets in question. The chapter explains why we consider the SKM 1998 value is the most appropriate in this matter for the application of the RFM, not the values in the SAIIR and ESCOSA decisions.
5. We then set out the assumptions regarding the useful life of the assets which we consider appropriate for the purposes of applying the RFM in this matter, and our basis for these. In our opinion:
   (a) a 20 year total average asset life should be assumed in respect of the period 1998 to 2005
   (b) a 28 year total average asset life should be assumed from 2005 to 2010.
6. The change in the assumed total asset life from 20 years to 28 years should be applied prospectively from 2005, not backdated to 1998. We explain the basis for this.
7. We then explain why we have not adopted SAPN's submission that the starting RAB should be determined by rolling forward the ESCOSA 2009 valuation. While it is appropriate for us to have regard to the ESCOSA decision, and we have had regard to it, we consider SAPN's proposal would lead to a determination under which charges in the 2010 to 2015 period significantly exceed the costs SAPN incurred in providing the service.
8. We conclude our discussion of the opening RAB with our assessment of the PLC submission explaining why we do not agree that the methodology developed by Houston Kemp should be used to establish an opening RAB. We consider it preferable to use the RFM.

[100] Sapere report May 2018; Sapere report January 2019; Sapere workbook 'SAPN_RollForward_and_PTRM_model_v1.7'.

6.3 How the regulatory principles apply

We must determine the opening RAB such that this access determination gives effect to the regulatory principles. The following regulatory principles are particularly relevant to the dispute concerning the opening RAB value.

Our determination must be made in a manner that will or is likely to contribute to the NEO, which requires us to (inter alia) promote efficient investment in electricity services, and their efficient operation and use, for the long term interests of consumers of electricity, with respect to price, quality, safety and security of supply of electricity.

Our determination must apply the NDSC, the following of which are particularly relevant here:

- NDSC 1, which requires that the price and conditions of access to the street lighting service should promote the achievement of the NEO
- NDSC 2, which requires that the terms and conditions of access to the service must be fair and reasonable and consistent with the safe and reliable operation of the power system
- NDSC 5, which provides that the price for a negotiated service must reflect the costs that a distributor has incurred or incurs in providing that service, based on the relevant cost allocation method
- NDSC 6, which provides that the price for a negotiated distribution service should be between avoidable cost and stand alone cost
- NDSC 11, which requires that the price for the service must be such as to allow a DNSP to recover the costs of regulatory obligations and requirements associated with its provision.

We must take account of the RPPs in making this access determination. The matters which we must take into account under the RPPs in determining the RAB are substantially addressed by the NDSCs, with two additions:

- RPP 2, which requires that the service provider should have a reasonable opportunity to recover at least the efficient costs incurred in providing the services in accordance with the law
- RPP 4, which requires that regard should be had to the regulatory asset base with respect to a distribution system adopted in any previous determination or decision under jurisdictional electricity legislation regulating the revenue earned or prices charged by a person providing services by means of that distribution system. [101]

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[101] There is a legal question whether RPP 4 applies to this dispute, as noted by the Expert Review Panel, and referred to by SAPN. Whilst the PLCs contended in their reply submission dated 30 August 2017 (footnote 9) that RPP 4 did not apply, they did not make that argument in any subsequent submissions. In our view, it is unnecessary for us to decide this legal issue in order to determine the access dispute. This is because we take the view that it is appropriate, in determining the dispute over the RAB, to have regard to the regulatory asset base with respect to the distribution system (or the relevant part of it) adopted in previous determinations regulating the prices charged for street lighting services in South Australia - specifically, the determinations by ESCOSA and the SAIIR. We consider that the regulatory asset base adopted in those determinations, and the determinations more broadly, are matters relevant to the issues arising for our decision in this access dispute (see NER 6.22.2(d)(1)). They are relevant for various reasons, including because they are determinations made by regulators with respect to SAPN's public lighting charges in periods preceding the period governed by the AER's determination, and so aspects of their approach may (depending on the circumstances) provide guidance to the AER in its

We must also give effect to the principle in rule 6.22.2(e) of the NER, which provides in relevant part that access charges should be based on the costs reasonably incurred by the DNSP in providing distribution network user access. In this context, we have sought to give effect to this principle by seeking to ensure that the charges for SAPN's service reflect its efficient costs in providing the service.

SAPN's submissions emphasise aspects of the regulatory principles that support regulatory consistency, in support of its submission that we should determine the RAB by rolling forward the value determined by ESCOSA.

Regulatory consistency regarding asset values is expressly provided for by RPP 4, to which SAPN draws attention. SAPN submits that 'the principles underpinning the NEO and the RPPs, which require consistency in the approach to asset valuation, as this provides certainty and predictability to investors, thus promoting efficient investment'[102], supports its approach. SAPN submits this approach is also consistent with the NDSC, 'which provide for the recovery by SAPN of the economic costs incurred in providing SLUOS, including a return on and of capital'.[103]

SAPN referred to what the High Court said, in the context of the Gas Code:[104]

> *Stripped to essentials, such a regime is at least intended to allow efficient costs recovery to a service provider and at the same time ensure pricing arrangements for the consuming public which reflect the benefits of competition, despite the provision of such services by monopolies. The balancing of those objectives properly has a natural flow on effect for future investment in infrastructure in Australia.*
>
> *The greater the degree of uncertainty and unpredictability in the regulatory process, the greater will be the perceived risk of investment. The greater the perceived risk of investment, the higher will be the returns sought.*

We accept these comments apply equally to the electricity regulation framework applying to this dispute. We further accept SAPN's submissions insofar as they advocate the proposition that certainty and predictability in regulatory outcomes, and access determinations, is desirable. We accept that the regulatory principles direct our attention to the promotion of certainty and predictability in making this determination. However, we do not accept that those factors should be determinative. Depending on the circumstances, a proper balance of all matters relevant to our decision, including (e.g.) the need to ensure that the price for a negotiated service reflects a distributor's efficient costs incurred in providing the service (see NDSC 5, 6 and 11 and RPP 2) may lead us to adopt a determination that differs from the approach taken in a prior regulatory decision.

SAPN submitted that the approach of rolling forward the ESCOSA RAB is consistent with 'the practice uniformly adopted by Australian regulators over the past decade of determining RAB values based on the most recent regulatory determination, appropriately rolled forward,

determination. Further, the parties' submissions on why their respective cases should be adopted draw on aspects of those prior determinations. In other words, even if RPP 4 does not strictly apply to the access dispute, we nevertheless consider it is appropriate to have regard to the RAB adopted by ESCOSA, and previously by SAIIR. A similar approach was adopted by the Expert Review Panel.

102 SAPN submission, August 2017, para 49, p. 12.

103 SAPN, submission, August 2017, para 49, p. 12.

104 East Australia Pipeline Pty Ltd v ACCC [2007] HCA 44, at 49-50.

rather than re-opening past determinations'.[105] Whether or not this submission is correct factually, we do not accept that the regulatory principles require us to roll forward the most recent determination by a regulator of the RAB in all circumstances. We address SAPN's submission on this point in detail in section 6.9 below.

The PLCs submitted that in considering the opening RAB, we should give effect to a 'whole-of-life principle'. This principle is that depreciation should be set in a manner that enables the service provider to recover the value of its capital investments in its assets, over the life of the assets. This means the total depreciation recovered (or return of capital) in respect of capital assets should not exceed the value of those assets.

We agree that the regulatory principles require us to seek to give effect to the whole-of-life principle. It is relevant to the regulatory principles that require prices and terms to be set so as to allow a DNSP to recover its efficient costs and investment in providing the service reliably, safely and in accordance with regulatory obligations, to be fair and reasonable and in the long term interests of consumers of the service. The whole-of-life principle therefore promotes RPP 2, and gives effect to NDSC 1, 2, 5, 6 and 11. The principle is directly reflected in clause 6.5.5(b)(2) of the NER, which applies in its terms to building block determination for standard control services but is instructive. In relation to depreciation, the NER provides:[106]

> *The sum of the real value of the depreciation that is attributable to any asset or category of assets over the economic life of that asset or category of assets (such real value being calculated as at the time the value of that asset was first included in the regulatory asset base for the relevant distribution system) must be equivalent to the value at which that asset or category of assets was first included in the regulatory asset base for the relevant distribution system.*

While this requirement is not expressed to apply to negotiated services, we consider it is consonant with the regulatory principles described above. Further, the process for setting a price for standard control services is one that seeks broadly to achieve the same objectives as the process for setting prices for negotiated control services.

In addition, if depreciation were set such that service providers received depreciation worth more than the value of the assets to which the depreciation relates (in other words, if service providers received 'return of capital' payments greater than the value of the investment they contributed) this would not promote, and would frustrate, the NEO (and hence NDSC 1). If regulatory outcomes allowed such excess depreciation, this would encourage inefficient investment, by providing an excessive investment incentive. This would also distort consumption decisions and be contrary to the long term interests of consumers, as charges paid for such services would be greater than is necessary to ensure their safe, efficient and reliable provision.

The whole-of-life principle is not necessarily in conflict with the promotion of regulatory certainty. As can be seen from the words of the High Court in *East Australia Pipeline Pty Ltd v ACCC* cited above, certainty in investment arises from the goal of ensuring that investors can invest knowing they can recover at least their efficient costs. The whole-of-life principle

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105 SAPN submission, August 2017, para 49, p. 12; see similarly SAPN's submission on the draft determination, paras 45-46, p. 9.

106 NER, cl. 6.5.5(b)(2).

directs attention to the time period over which one looks to determine that an investor's efficient costs can be recovered.

While SAPN's initial submissions questioned whether the whole-of-life principle arose under the NEL or the NER, it did not press this submission, and subsequently indicated that it did not contest the existence of the principle. [107]

The regulatory principles that govern the dispute concerning the opening RAB do not indicate a particular determination of the dispute. The applicable principles require us to promote and give effect to a range of considerations and principles, and we must make a determination that we consider best gives effect to them considered holistically.

As we discussed above in Chapter 5, this task requires us to exercise our judgment in the broader regulatory context, so as to arrive at a determination that best balances the regulatory objectives and contributes to the NEO.

6.4 What the parties say

6.4.1 The PLC's submissions

The PLCs submitted that the public lighting charges they paid from 1 July 1998 at least until 2008 were at a level consistent with a pricing model that allowed for a depreciation allowance based on an assumed asset life of 20 years.[108] The PLCs submitted that ESCOSA, in determining whether public lighting charges paid between 1 July 2005 and 30 June 2009 were ‘fair and reasonable’, determined a RAB by rolling forward the 1998 SKM value using a model which assumed that street lighting charges paid from 1998 to 2005 included a depreciation component based on a 28 year asset life.[109]

The PLCs submitted that, as a result of the differing asset life assumptions, the ESCOSA roll forward calculations inflate the RAB, undervaluing the depreciation payments made by the PLCs prior to 2005. In particular, these calculations are said to result in a closing RAB as at 2009 that is too high.

The PLCs provided a report from Houston Kemp setting out what it says is the correct method to calculate the opening RAB value and the overpayments made by the PLCs for the dispute period. The PLCs instructed Houston Kemp to make this assessment on the basis that SAPN adjusted the assumed asset life of street lighting assets from 20 years to 28 years from 1 July 2005.

The PLCs described the RAB issue as being:[110]

> *…whether applying straight-line depreciation, on a 28-year asset life assumption, from the 1998 opening value would be consistent with whole-of-life depreciation principles,*

[107] Transcript May 2018, line 28, p. 42. SAPN asserts that, in any case, its actual 2010-2015 charges reflect its costs and do not violate the whole-of-life principle. This is discussed further below in sections 6.4 to 6.7. Further, as a result of SAPN's approach to the ESCOSA decision, SAPN contends that the whole-of-life principle is ‘properly applied from 1 July 2005 onwards’: SAPN submission in response to the draft determination, para 46, p. 9. We address SAPN's submissions on the ESCOSA decision below in section 6.9.

[108] PLC, Reply submissions, 20 September 2017, para 25, p. 5.

[109] ESCOSA, Fair and Reasonable Determination December 2009, Appendix 1.

[110] PLC submission, September 2017, para 28, p. 6.

in circumstances where SAIIR's earlier review has been done using a 20-year assumed asset life.

Following the Draft Determination, the PLCs said that it is appropriate to use the net present value (NPV)-based adjustment adopted by Houston Kemp instead of determining the opening RAB by using a roll-forward model, because the AER has only previously applied its RFM in conjunction with PTRM regulation (or its equivalent) in the immediately preceding period. In circumstances where SAPN's assets were not previously subject to PTRM regulation, and there is thus no previously-determined depreciation allowance to input into the RFM, the PLCs said that applying the RFM to those assets lacks the logical coherence of its proposed methodology and is inconsistent with the AER's previous regulatory practice.[111]

The PLCs also submitted that using the AER's RFM to determine the opening RAB also contained two inconsistencies leading to a material over-calculation of the opening RAB. First, they said that the AER's RFM provided for no depreciation on new capital expenditure in the year that it is incurred, whereas the financial model that SAPN used to determine public lighting tariffs allowed a whole year's depreciation on new capital expenditure in the year it is incurred. Secondly, they said that the AER's RFM provided for the capitalisation of a half year return on new capital expenditure in the year that it is incurred, whereas SAPN's financial model indexed new capital expenditure for a half year of inflation but did not include the capitalisation of any real return.[112]

6.4.2 SAPN's submission

SAPN's position on the opening RAB is that, notwithstanding PLCs submissions as to what might have occurred prior to 2005, the regulatory principles require that the AER use ESCOSA's 2009 determination as the starting point for setting the RAB at 1 July 2010.

SAPN proposed an opening RAB of $40.14 million[113] based on the following methodology:

- The starting point is the asset value which ESCOSA calculated for 2008/09 by rolling forward the 1998 SKM valuation using capital expenditure, inflation and depreciation on the basis of an assumed total life for the assets of 28 years.
- The 2008/09 ESCOSA value is then rolled forward to 2010 in the same manner – i.e. to reflect actual capital expenditure, inflation and depreciation on the basis of an assumed total life for the assets of 28 years.[114]

SAPN argued the ESCOSA value should be the starting point, on the basis that it is the most recent regulatory determination of a RAB for street lighting services. According to SAPN, adopting an updated ESCOSA value is consistent with:[115]

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[111] PLC submission in response to the draft determination, paras 6-15, pp. 2-4; see also supplementary Houston Kemp report, 11 March 2019 at pp. 4-5.

[112] PLC submission in response to the draft determination, para 17-18, p. 3; see also supplementary Houston Kemp report, 11 March 2019 at pp. 7-8.

[113] SAPN submission, August 2017, para. 48, p. 12.

[114] Incenta Economic Consulting, Determining the value of SA Power Networks' Public Lighting Assets - Report for SA Power Networks, August 2017, para 47, p. 14. SAPN's roll forward model excludes inflation indexation from the accumulated capex used to calculate the depreciation on new assets. Correcting this error results in a closing RAB value of $40.08 million as at 30 June 2010.

[115] SAPN submission, August 2017, para 49, p. 12.

- the principles underpinning the NEO and RPPs, which require consistency in the approach to asset valuation to provide certainty and predictability to investors thus promoting efficient investment
- the practice of regulators to determine RAB values based on the most recent regulatory determination appropriately rolled forward rather than re-opening past determinations
- the NDSC, which provide for the recovery of the economic costs of providing public lighting services, including a return on and of capital.

SAPN submitted that 'reopen[ing]' and 'adjust[ing]' a previous regulator's determination would greatly undermine certainty for access providers and customers.[116] It also submitted that ESCOSA had 'expressly contemplated that its determination of the asset value and asset life assumptions would be used as the basis for future determinations';[117] that ESCOSA's decision to adopt a longer asset life than SAPN had proposed was clearly explained and justifiable;[118] and that there is no evidence that ESCOSA overvalued SAPN's public lighting assets.[119]

SAPN contended that, contrary to the PLC's submission, it is not established that adopting the ESCOSA value as the opening RAB breaches the whole-of-life principle. SAPN submitted that, in making this assertion, the PLCs rely on several contentions, none of which they have made out.[120] Most notably, the PLC's have not established that street lighting reviews were set using a building block method prior to 2005. Nor have they established that the SAIIR decision in 2000 involved a depreciation allowance based on a 20 year asset life, which then formed part of SAPN's charges from then onwards. SAPN submitted that the revenue it collected in the pre-2005/06 period did not include a cost component reflecting a 20 year asset life, and that SAIIR did not purport to establish a basis for recovery of capital costs for the period 1 July 1998 to 30 June 2005.[121]

6.5 Why we are using the RFM to establish the opening RAB

The RFM is the model developed by the AER as required by NER clause 6.5.1(b) to determine the closing RAB for a regulatory control period. The closing RAB for a regulatory control period becomes the opening RAB for the purpose of making a building block determination (using the PTRM) for the next regulatory control period.

The RFM is an integral part of the regulatory mechanism established by Part 6 of the NER. In addition to determining the opening RAB, it determines the opening TAB and the weighted average remaining life of the regulated asset. These are key inputs to the PTRM.

The RFM is applied to calculate the closing RAB value at the end of a regulatory control period, and takes account of actual outcomes over the course of the period just ended (such as the actual CPI and actual net capex). The PTRM also contains an asset base roll forward

116 SAPN submission in response to the draft determination, para 44, p. 9.

117 SAPN submission in response to the draft determination, para 31, p. 7.

118 SAPN submission in response to the draft determination, paras 37-41, p. 8.

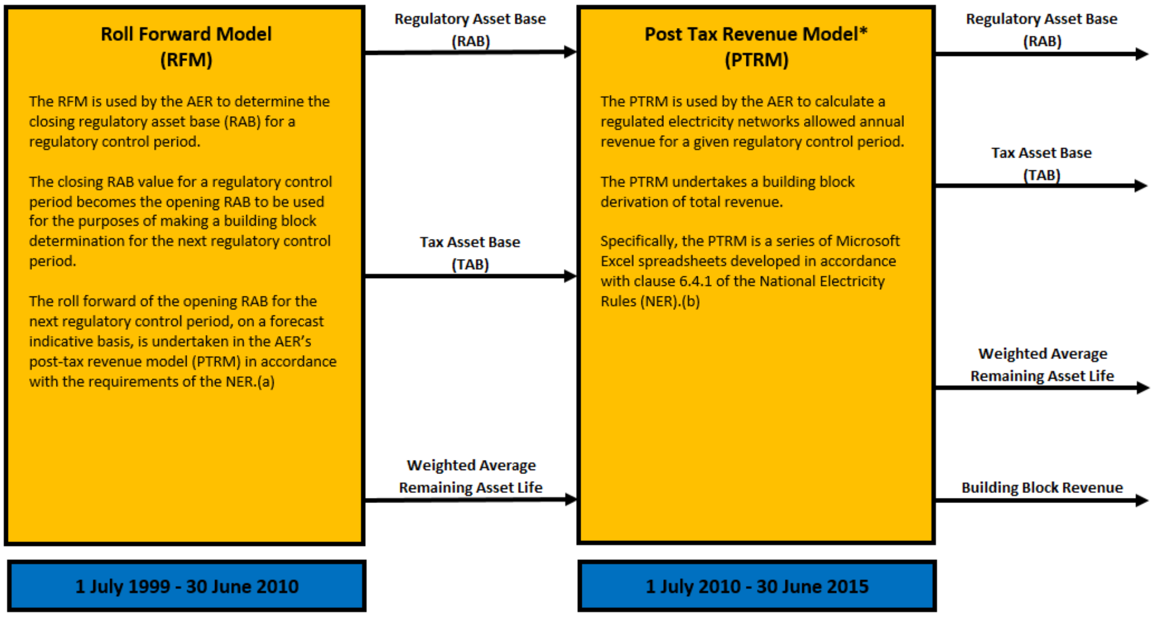
119 SAPN submission in response to the draft determination, para 47, p. 9.

120 SAPN submission, October 2017, para 29 ff, p. 5.

121 SAPN submission in response to the draft determination, para 53, p. 10.

mechanism, but is forward looking - it rolls forward the opening RAB for the new regulatory control period on a forecast indicative basis.

Figure 6-1 Relationship between RFM and PTRM



(a) https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/roll-forward-model-distribution-december-2016-amendment
(b) https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/post-tax-revenue-models-transmission-and-distribution-january-2015-amendment

We are not required to use the RFM to establish an opening RAB in the present dispute, since it applies as a matter of law only to standard control services and not to negotiated services. However we consider it is appropriate to do so.

Firstly, the RFM provides the standard method for establishing an opening RAB for input to the PTRM, which the parties accept we should use to resolve this dispute. The RFM employs a straightforward and well understood methodology.

Secondly, we consider the RFM gives effect to the regulatory principles, provided the inputs (the starting value, the asset life and some other variables) are appropriate. Properly applied, the RFM results in asset values being adjusted over time to account for inflation, net capex and depreciation. The resulting asset values are then an appropriate foundation for calculating capital charges which reflect the efficient cost of service provision and allow for the value of investment to be recovered over the life of the asset.

Nothing in SAPN's submissions suggest it has concerns of principle at applying the RFM to establish the opening RAB. SAPN's methodology uses a similar roll-forward methodology to the AER's RFM,[122] albeit that SAPN proposes a different starting value (based on ESCOSA's 2009 decision) and asset life assumptions. If the AER does not use the ESCOSA value to establish the opening RAB, SAPN's position is that the AER's RFM should be applied ‘in its entirety’.[123]

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122 See, e.g., SAPN submission in response to the draft determination, para 4, p. 2 (‘SAPN agrees with the AER that the appropriate method for establishing the opening RAB is a standard roll forward calculation, with straight line depreciation’).

123 SAPN submission in response to the draft determination, paras 71-72, p. 13.

The PLCs proposed an alternative method to establish an opening RAB, rather than the RFM. For the reasons set out below, we are not persuaded we should depart from the RFM to establish the opening RAB for this determination (section 6.10).

The RFM commences with a reliable starting valuation, which is rolled forward from year to year adjusting for net capex, inflation and depreciation. To apply the RFM, we must decide (a) what value to adopt as the starting value, and (b) what asset life to assume for the purpose of calculating capital charges under the model.

6.6 Why SKM is our starting value for the RFM

The starting value for the RFM is a key issue in the dispute as it has a significant impact on the opening RAB value. The PLCs have submitted that the 1998 SKM value should be rolled-forward to establish the opening RAB, while SAPN contended we should roll-forward a value from the 2009 ESCOSA report.

In the present dispute we consider the most appropriate starting value is the valuation at 30 June 1998 prepared by SKM.[124]

The parties accept the 1998 SKM valuation as a reliable estimate of the value of the assets as at 1998. None of the submissions have expressed concerns as to its reliability, and the SKM value is a key input in the methodologies for which each party has contended:

- The SKM valuation is a foundation of the RAB conclusions in ESCOSA's 2009 'fair and reasonable' inquiry,[125] which SAPN submitted provides the basis to establish the RAB for this dispute[126]
- The SKM valuation is the starting point for Houston Kemp's methodology, which the PLCs submitted provides the correct RAB for this dispute.

The SKM valuation covered all system assets[127] forming ETSA Utilities' electricity distribution system, not merely the public lighting assets. SKM's valuation of the electricity distribution system (not including the public lighting component) was the foundation of the electricity distribution system RAB under the regulatory framework applying to ETSA Utilities' distribution services upon privatisation. Rolled-forward, the SKM value (net of the public lighting component) was adopted as the RAB under the NER.[128]

Adopting the SKM value as the starting value for the RFM, instead of a value derived from the ESCOSA 2009 report as urged by SAPN, is a decision we have not taken without carefully reflecting on whether the latter approach gives effect to the regulatory principles.

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124 SKM September 1999. This report was based on a report prepared by SKM in 1995, and was described as a high level assessment of changes covering, among other things, additions, deletions and depreciation since 1995, and review of standard asset lives.

125 ESCOSA Fair and Reasonable Determination 2009, para 77, p. 15.

126 SAPN submission, August 2017, para 48, p. 12.

127 The SKM 1999 report covers all system assets in ETSA Utilities electricity distribution system, but does include non-system assets including land, buildings, vehicles, plant and tools and office equipment: p. 17.

128 The Electricity Pricing Order prescribed a RAB value for ETSA Utilities' distribution business by rolling forward the valuation as at 1998 in the SKM 1999 report. ESCOSA later rolled forward this value (i.e. the RAB value from the Electricity Pricing Order) to provide an opening RAB for the Electricity Distribution Price Determination for the 2005 to 2010 regulatory control period: ESCOSA, Electricity Distribution Price Determination Part A, p. 103. This last-mentioned value was later determined by the NER cl. 6.2.1(c) as the opening RAB for ETSA Utilities' distribution asset base at 1 July 2005.

However, for the reasons in section 6.9, we have concluded the valuation determined by ESCOSA in 2009 is not an appropriate value for an opening RAB in this dispute. Weighing all the matters that arise for our consideration (see sections 5 and 6.3 above), as well as the parties' submissions, we have decided that adopting the ESCOSA value would not give effect to, and would ultimately be inconsistent with, the regulatory principles - most importantly, because this value would result in access charges for 2010 to 2015 that exceed the efficient costs of providing those services.

We have considered SAPN's submission that departing from ESCOSA's valuation in establishing the opening RAB would undermine ‘certainty and predictability’ for both access providers and customers, and ‘set a precedent for reopening of regulatory determinations in future’.[129] Whilst we have taken into account the desirability of promoting certainty and predictability in regulatory outcomes, this is one of several factors that we must weigh in our determination. We do not accept that it requires us to select an outcome that would lead to charges exceeding efficient costs and, thus, would not contribute to the achievement of the NEO or give effect to regulatory principles including NDSC 5, 6 and 11.

We also consider that SAPN overstates the impact of our favoured approach on regulatory certainty, having regard to the matters discussed at section 6.9 below.

Further, although we accept that our mandate to give effect to the regulatory principles requires the AER to pursue a fair outcome for the parties,[130] that means fairness for the consumer as well as for the service provider - and if we conclude, as we have in this determination, that the PLCs been charged excessive amounts for public lighting services, it would be unfair to deny them recompense for that. Relatedly on the topic of fairness, we have taken into account SAPN's contention that it would be unfair to reject the ESCOSA roll forward calculation in circumstances where ‘the decision by ESCOSA in relation to asset lives was supported at the time by all stakeholders, including the [PLCs]’[131] and the PLCs did not raise objections to that analysis at the time of the original ESCOSA decision, or indeed until 2017.[132] The submission dated September 2009 that was prepared by Trans-Tasman Energy Group on behalf of the PLCs and submitted to ESCOSA indicates to us that the PLCs did not support the retrospective application of a 28 year asset life back to 1998, which was the approach ultimately taken by ESCOSA. Rather, the PLCs accepted that the revised asset life assumption should apply from 2005 onwards, using a roll forward asset base at 2005 based on the regulatory accounts submitted by SAPN[133]. Those accounts used a 20 year asset life based on roll forward of the 1998 SKM value. We discuss these matters further in section 6.9 below. In any event, even if the PLCs could have raised their complaint as to the asset life assumption earlier - balancing the various factors arising for our

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129 SAPN submission in response to the draft determination, paras 62-64, p. 12.

130 See SAPN submission in response to the draft determination, paras 65-69, pp. 12-13.

131 SAPN submission in response to the draft determination, para 6(b), p. 3; see also letter from SAPN's CEO to AER dated 13 March 2019, pp. 1, 2, 3.

132 SAPN submission in response to the draft determination, paras 6-7, pp. 2-3; see also letter from SAPN's CEO to AER dated 13 March 2019, pp. 1, 2, 3.

133 Trans-Tasman Energy Group, September 2009:

p.7 (first dot point under heading Negotiation)

Addendum C - Asset Charges Paper, p7 of 8 (see heading Important).

Addendum C - Asset Charges Paper, p8 of 8 (see heading Important).

consideration, we have concluded that a proper application of the regulatory principles favours a departure from the ESCOSA valuation. Finally, we do not accept SAPN's submission that the whole-of-life principle is properly applied from 1 July 2005 as this was the last date that a regulator (ESCOSA) determined the RAB, and that ESCOSA's assumptions in adopting that value should not be critiqued.[134] To ignore everything that came before ESCOSA in the manner SAPN proposes would permit SAPN to recover more than its efficient costs for the period the subject of this dispute. We have concluded that the whole-of-life principle properly applies from 1998, when an asset valuation was undertaken by SKM for the Electricity Reform and Sales Unit within the South Australian Department of Treasury and Finance.

6.7 The basis for our asset life assumptions

The useful life of an asset determines the rate at which capital must be recovered so that a service provider can recover its investment over the asset's lifespan. A shorter lifespan dictates a faster rate of recovery, a longer lifespan a slower rate. In economic theory, an owner intending to recover no more than its investment in an asset would be indifferent to the rate of recovery (if an adjustment is made for the time value of money).

When the useful life of an asset is revised part way through its life, the remaining value of the asset must be depreciated over its remaining life if the service provider is to recover no more or no less than its investment. The assumed asset life may change if, for example, it is found that the assets have a longer or shorter technical life than initially reckoned. These premises promote the regulatory principles, as they arise from the whole-of-life principle (discussed in section 6.3).

As discussed in the following paragraphs, the weight of the material we have considered in this matter leads us to adopt an assumed total asset life of 20 years for the period from 1 July 1998 to 30 June 2005 and, consistent with the position of ETSA Utilities, the PLCs and ESCOSA, to increase the assumed total asset life to 28 years from 1 July 2005 onwards.

6.7.1 Asset life assumed by SKM

The SKM valuation – the starting point for all of the RAB methodologies under consideration – assumes a 20 year asset life. This is clear from table 5.1 of the SKM report (reproduced as figure 6-2 below).[135]

[134] SAPN submission on the draft determination, paras 45-46, p. 9.

[135] SKM 1999, p. 7.

Figure 6-2 Standard Lives assumed by SKM

Equipment Category	Revaluation (95)	Review (98)
Overhead lines distribution	45	55
Overhead lines sub-transmission	45	55
Underground cables		55
Transformers	45	45
Switchgear	45	45
Public Lighting	20	20
Meters, Services	35	30
Substations	45	45
Communications	15*	15

Source: SKM, ETSA Utilities Asset Valuation - Final, September 1999.

SKM used a standard asset valuation methodology to arrive at a 'depreciated' ORC value (or 'ODRC') of $37.07 million:

- Firstly, it estimated the cost of replacing the assets with the most efficient technology (the 'optimised replacement cost' or 'ORC'). SKM's estimated ORC value for public lighting assets was $66 million in 1998.[136]
- Secondly, SKM adjusted the ORC value to reflect that the assets were not new at the valuation date. Rather, by 1 July 1998, the assets were assessed to be on average nine years of age, with 11 years of the assumed 20 year asset life still to come.[137]

In other words, SKM used straight-line depreciation over a 20 year period - reflecting an assumed asset life of 20 years - when adjusting its ORC estimate downwards to arrive at an ODRC value. Had SKM assumed an asset life other than 20 years, the written down value at 1 July 1998 would also have been different. A longer assumed lifespan would result in a higher written down value at 1 July 1998, because proportionally less of the investment would be taken to have been recovered by 1998. Conversely, a shorter assumed lifespan would produce a lower written down value of the assets.

This connection was acknowledged by ETSA Utilities in its submission to SAIIR:[138]

> *It should be noted that the initial Sinclair Knight Merz asset value assessment determined an asset life of 20 years, with an explicit remaining asset life for that*

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136 SKM 1999, pp. 9, 12.

137 Although the SKM 1999 report assumed an average total life of 20 years, it did not state the average age or the remaining life of the public lighting assets.

In modelling SAPN's street lighting asset base and revenues for 2010 to 2015, Sapere assumed that the assets were nine years old on average at the time of the SKM valuation. Sapere based this estimate on its analysis of the 'gross asset value' and 'written down asset value' figures in Box 3.1 on page 26 of SAIIR 2000, reproduced in section 6.7.2 below: Sapere report January 2019, para 9, p. 6.

However the ESCOSA 2009 decision assumed an average age of 10 years, not nine years: ESCOSA Fair and Reasonable Determination 2009, Appendix 1.

Incenta concurs with Sapere that ESCOSA's assumption of an average age of 10 years was in error: Incenta August 2017, para 74(b), p. 24.

138 SAIIR 2000, p. 24.

valuation. It should be noted that if the asset life was now deemed to be different for regulatory purposes the current depreciated asset value should also be changed.

6.7.2 SAIIR's asset life assumption

SAIIR's inquiry assumed a 20 year lifespan for the public lighting assets. This assumption fed into its assessment of ETSA Utilities' cost base, against which SAIIR concluded public lighting charges for the year 2000-01 were 'fair and reasonable'.[139]

The information before SAIIR did not uniformly point to 20 years. SAIIR obtained data from ETSA Utilities on gross asset values, which indicated the weighted average life for public lighting assets was 28 years. However, ETSA Utilities explained that this data was used in its pricing model 'to determine pricing relativities between different light types', and should not be used to determine overall revenue targets for depreciation and return on assets.[140]

However, SAIIR recognised that if it departed from 20 years this would affect the starting asset value as determined by SKM. Therefore, SAIIR maintained the asset life at 20 years for assets existing at the time of the SKM valuation, but suggested ETSA may revise the assumption on street lighting asset life for new capital expenditure.[141]

SAIIR drew support from the fact that a 20 year lifespan is commonly used by other jurisdictions.[142] ETSA Utilities also favoured 20 years at this time, its submission to SAIIR stating:[143]

> *…the 20 year asset life was reviewed in 1995 and 1998 by Sinclair Knight Merz and found suitable. Moreover, Burns and Roe Worley in their review noted that the economic life of 20 years for public street lighting was 'reasonable and also in line with the practice adopted by Victorian power utilities.*

SAIIR further stated:[144]

> *…there has not been any empirical evidence presented to the SAIIR suggesting that 20 years is unreasonable for street lighting assets. The 20 year asset life has been reviewed and agreed to on three occasions in the last five years. This asset life is also consistent with that applied in other States.*

The assumption of a total asset life of 20 years is consistent with the asset roll-forward table provided by ETSA Utilities and accepted by SAIIR as 'fair and reasonable'.[145] This table is reproduced as figure 6.3. While the table does not state the asset life assumption, we have back-solved this from the asset and depreciation values in the table. Using the written down asset value from the table ($37.07 million at 1 July 1998) and a remaining asset life of 11 years (consistent with a total life of 20 years, given the assets had an average age of 9 years at 1 July 1998), the resulting asset and depreciation values are closely comparable (i.e. within 0.5 percent) with the values in table 3.1 of the SAIIR report.

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139 SAPN's oral and written submissions include a number of statements that SAIIR did not use a building block methodology to determine charges e.g. SAPN submission, October 2017, para 33 ff, p. 6. However SAPN does acknowledge that SAIIR used a building block model as part of its assessment, but not to lock-in revenue allowances or capital recoveries: SAPN October 2017 para 37, p. 7.

140 SAIIR 2000, p. 24.

141 SAIIR 2000 p. 24.

142 SAIIR 2000, p. 24.

143 SAIIR 2000, p. 24.

144 SAIIR 2000, p. 25.

145 SAIIR 2000, Box 3.1 Asset roll-forward, p. 26.

Figure 6-3: ETSA Utilities' asset roll forward table 1998/99 to 2000/01 ($ million, nominal)

Box 3.1 Asset roll-forward

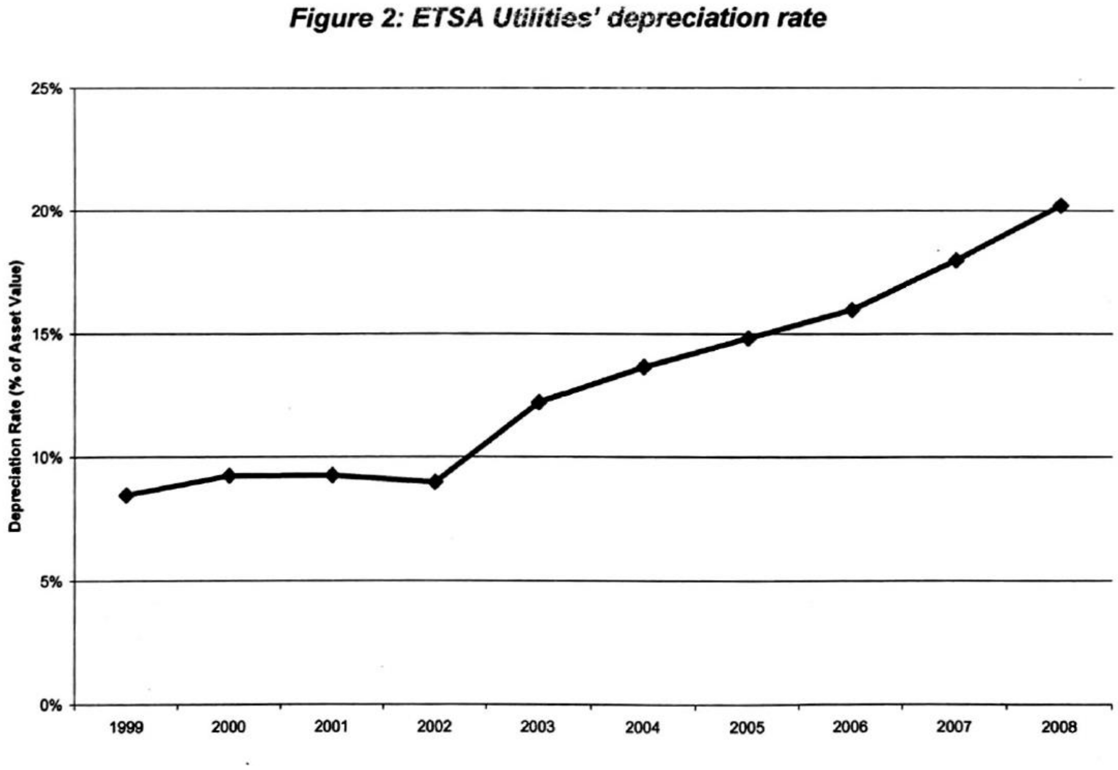
ASSET MOVEMENT	GROSS VALUE	WRITTEN DOWN VALUE	NOTES/SOURCE:
Balance 1 July 1998	66.13	37.07	SKM valuation
Escalation 1 July 1998	0.83	0.46	@ 1.25% CPI
Cap Ex 98/99	3.68	3.68	
Escalation Capex	0.02	0.02	
Depreciation 98/99		(3.49)	
Balance 30 June 1999	70.66	37.75	
Escalation 1 July 1999	1.97	1.05	@ 2.79% CPI
Cap Ex 99/00	2.20	2.20	
Cap Contrib 99/00	-0.33	-0.33	
Escalation Capex/CC	0.03	0.03	@ 2.79% CPI × 0.5
Depreciation 99/00		(3.76)	
Balance 30 June 2000	74.52	36.94	
Escalation 1 July 2000	2.24	1.11	@ 3% assumed CPI
Cap Ex 00/01	2.00	2.00	
Cap Contrib 00/01	-0.33	-0.33	
Escalation Capex/CC	0.03	0.03	@ 3% assumed CPI × 0.5
Depreciation 00/01		(3.96)	Based on the same rate as previous year
Balance 30 June 2001	78.46	35.78	

Source: SAIIR 2000, p. 26.

6.7.3 ESCOSA's asset life assumption

On the materials before us the assumption of a 20 year asset life was not revisited by the South Australia state regulator until 2009, in the course of ESCOSA's inquiry. ETSA Utilities submitted the following depreciation profile to ESCOSA.

Figure 6-4 ETSA Utilities' depreciation profile, 2008



Source: ESCOSA Statement of Issues 2008, p. 18

ESCOSA considered that ETSA Utilities’ depreciation profile would result in a substantial over-recovery of costs, unless prices were reduced substantially over time as the asset depreciated, at least until a significant asset replacement was required, when a sharp price increase would be required. ESCOSA considered neither of these scenarios (over-recovery or volatile pricing) were consistent with the outcomes expected in a competitive market. In its Statement of Issues released to the parties in 2008, ESCOSA stated 'the depreciation methodology currently adopted by ETSA Utilities in deriving its street lighting excluded services charges is not fair and reasonable'.[146]

ESCOSA’s Statement of Issues stated that depreciation rates in the range 10 percent +/- 2 percent would produce a price path that would not expose ETSA Utilities to material price volatility and hence risk.[147] ETSA Utilities' depreciation rate of 20 percent for 2007/08 was outside this range, and indicated an excess asset related charge of about $1.6 million for that year.[148] This indicated that the depreciation rate and asset related charges proposed by ETSA Utilities were too high and would have to be reduced in order to be considered ‘fair and reasonable’.

In response ETSA Utilities advised that, since the time of ESCOSA’s initial analysis in 2008, it had revised its depreciation schedule so as to use an average life of 28 years.[149] ETSA

146 ESCOSA Statement of Issues 2008, para 116, p. 19.

147 ESCOSA Statement of Issues 2008, para 109 p. 19.

148 ESCOSA Statement of Issues 2008, p. 20.

149 ESCOSA Fair and Reasonable Determination 2009, para 106, p. 19.

Utilities' revised asset life was supported by the PLCs[150] and accepted by ESCOSA.[151] ETSA Utilities' new depreciation schedule produced a depreciation rate within ESCOSA's acceptable range (i.e. 10 percent +/- 2 percent).[152]

ESCOSA's 2009 report concluded that the revised asset life of 28 years was an appropriate basis for calculating 'fair and reasonable' public lighting charges.[153]

6.8 Prospective application of revised asset life

When the useful life of an asset is revised part way through its life, the remaining undepreciated value, at the revision date, should be depreciated from that point in time onwards over the asset's remaining life.

This results in an asset owner recovering the value of its investment once over the life of the asset. This outcome is consistent with the regulatory principles and with clause 6.5.5(b)(2) of the NER.[154]

By contrast, retrospectively applying a revised asset life would result in an asset owner recovering more, or less than, the value of its investment. This outcome would be inconsistent with the regulatory principles governing this determination, in particular the cost recovery or whole-of-life principle.

6.9 Why we have not accepted SAPN's approach of using the ESCOSA value

We accept that there may be plausible arguments that the NEO is best served where a regulator, tasked to establish an opening RAB for the PTRM in a dispute concerning a negotiated control service, adopts a RAB value that has been established in an earlier regulatory determination, rolled-forward to adjust for capex, inflation and depreciation in the intervening period through the application of the RFM. Whether or not those arguments should be accepted will depend upon a range of matters, including the parties' positions on that prior RAB value, and how closely the earlier determination aligns with the functions and objectives of the subsequent regulator under the latter's regulatory scheme.

In the present matter there is not agreement as to the suitability of the state regulator's earlier public lighting determinations for this purpose. We have reviewed in detail the ESCOSA 2009 decision, which SAPN has submitted should provide the basis for the opening RAB, in order to decide whether that submission should be accepted and whether it is appropriate to use that decision to determine the opening RAB for this decision.

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150 It appears to us from the Trans-Tasman Energy Group submission (discussed in section 6.9.3 below) that the PLCs supported the application of a 28 year asset life assumption from 2005 onwards using a roll forward asset base as at 2005 based on the regulatory accounts submitted by ETSA Utilities.

151 ESCOSA Fair and Reasonable Determination 2009, para 107, p. 19.

152 ESCOSA Fair and Reasonable Determination 2009, p. 19.

153 ESCOSA Fair and Reasonable Determination 2009, para 110, p. 20.

154 Clause 6.5.5(b)(2) states 'the sum of the real value of the depreciation that is attributable to any asset or category of assets over the economic life of that asset or category of assets (such real value being calculated as at the time the value of that asset was first included in the regulatory asset base for the relevant distribution system) must be equivalent to the value at which that asset or category of assets was first included in the regulatory asset base for the relevant distribution system.'

As set out in the following paragraphs, our analysis leads us to conclude that deriving our opening RAB from the ESCOSA 2009 decision would not give effect to, and indeed would be inconsistent with, the regulatory principles we outlined above. In summary:

1. Outcome: On the material before us, we are satisfied that, from 1998 until 2005 at the earliest, a key parameter of ETSA Utilities' pricing was an expected average total asset life of 20 years. ESCOSA decided that it was appropriate to revise the depreciation schedule such that that asset life was moved to 28 years. Rather than applying this asset life from the period of its decision onwards, it applied it retrospectively, treating the RAB as if it had been being depreciated at 28 years since 1998, when it plainly had not. This resulted in a retrospective increase the value of the RAB, thus increasing SAPN's return on capital revenue violating the whole-of-life principle. ESCOSA's reasons for decision do not address why its change in asset life should have been applied retrospectively, nor the impact this would have on the value of SAPN's RAB and the appropriate return of capital over the life of the assets. In our view it follows that adopting an opening RAB based on the ESCOSA decision - which incorporated a total asset life of 28 years from 1998 onwards - would result in access charges for 2010 to 2015 that exceed the efficient costs of providing the services, and result in SAPN recovering more than its initial investment over the asset's life. Such a result would be inconsistent with the regulatory principles outlined above. This weighs against adopting a value from the ESCOSA 2009 report as the foundation for the opening RAB.

2. Clarity: We have formed the view that a number of significant aspects of ESCOSA's decision are unclear and unpersuasive. This is another factor that we consider weighs against relying on ESCOSA's decision to provide the foundation for an opening RAB.

3. Task: There are two related ways in which we consider that the nature of ESCOSA's task should lead us to exercise caution in relying upon ESCOSA's valuation. First, ESCOSA's task was not a forward looking price determination, wherein a regulator sets or approves tariffs ex ante, based on its assessment of the regulated entity's efficient costs and demand forecasts over a future period. Nor, indeed, is the AER's task in this determination. However, it is relevant that the regulatory scheme governing ESCOSA's function did not require it to produce a forward looking price determination that the scheme contemplated would be carried forward in subsequent determinations. In our view, this lessens the strength of the argument that ESCOSA's valuation should be followed in later regulatory decisions. Secondly, the precise nature of ESCOSA's function in its determination, and the economic test it applied, was to determine whether charges being levied during a particular period in time were 'fair and reasonable'. We consider that this is a different standard than what must be applied by the AER in this dispute. The AER is required (relevantly) to give effect to the regulatory principles in determining whether the charges for public lighting services in the dispute period were excessive and, if so, the quantum of the excess charges (see section 5 above). That task requires more precision than simply assessing whether certain charges fell within the range of prices that could be described as ‘fair and reasonable’. Again, this weighs against the submission that it is inappropriate to do anything other than use ESCOSA's analysis as the starting point for the AER's task.

6.9.1 ESCOSA's task

Both the SAIIR and the ESCOSA inquiries took place under a regulatory framework wherein the regulator did not set or approve tariffs ex ante as in a price determination. The ESCOSA report states this several times.[155] Rather, prices under this framework were set by the regulated entity, subject only to the constraint that they be 'fair and reasonable'.[156]

Prior to the dispute period the state regulator conducted two inquiries to consider whether ETSA Utilities' public lighting charges were 'fair and reasonable'. The first (SAIIR 2000) examined charges for the year 2000/01 while the second (ESCOSA 2009) examined the period 1 July 2005 to 31 December 2009. Consistent with the regulatory framework that applied at the time, in neither inquiry did the state regulator determine a precise tariff for any individual service or group of services - it simply assessed whether the charges overall were within an acceptable range.

This is recognised in SAPN's response submission, which says of the SAIIR inquiry:[157]

> *Even for that single year [2000/01] there was no determination of charges using a building block model or any other method. Rather, all the SAIIR found was that the charges that had been applied pursuant to the EPO lay within a reasonable range.*

SAPN's submission quotes SAIIR:[158]

> *The EPO states that the SAIIR is to adopt a 'light handed' approach to price regulation for these excluded services. Hence, this Inquiry is not a price determination, but seeks to assess whether current street lighting charges are fair and reasonable -* **or lie within an acceptable range** *– given the quality of service supplied.*
>
> *(Emphasis added)*

Likewise ESCOSA stated that:[159]

> *It is clear from the regulatory framework established to control ETSA Utilities' pricing in relation to excluded services that the relevant question which the Commission must address in this matter is whether ETSA Utilities' public lighting excluded services prices are fair and reasonable. Provided those prices are established to be fair and reasonable***, it does not matter that there may be other charges or methodologies which are also fair and reasonable or may be considered by others to be 'more' fair and reasonable***.*
>
> *(Emphasis added)*

ESCOSA proceeded at a high level of generality, examining ETSA Utilities' public lighting costs and revenues over the review period as a whole. ESCOSA did not purport to examine prices for individual services or groups of services, nor did it draw conclusions as to the relationship between costs and revenues for individual years.

Instead ESCOSA determined a 'fair and reasonable average annual revenue of $14.32 million.[160] This was based on ESCOSA's findings as to the average annual revenues

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155 ESCOSA Fair and Reasonable Determination 2009, para 4, p. 9; para 59, p. 11.

156 The considerations relevant to whether a price is 'fair and reasonable' are discussed earlier in these reasons at sections 3.1 and 3.2.

157 SAPN, 30 August 2017, para 36, p. 7.

158 SAPN, 30 August 2017, para 36, p. 7, quoting SAIIR 2000, p. 4.

159 ESCOSA Fair and Reasonable Determination 2009, para 54, p. 11.

160 ESCOSA Fair and Reasonable Determination 2009, pp. 36-37.

for each cost component over the four year period 1 July 2005 to 30 June 2009, reproduced in figure 6-5.

Figure 6-5 ESCOSA findings - 'fair and reasonable' average annual revenue for public lighting excluded services for the period 1 July 2005 to 30 June 2009

ALL VALUES ARE IN $M (UNLESS OTHERWISE SPECIFIED)	FINAL DECISION
Avg. Asset Value	40.74
ROA	2.91
Dep	3.50
O&M	6.70
Elevation	1.21
Profit Margin	0.00
Total	**14.32**

Source: ESCOSA 2009, p. 36.

ESCOSA compared the average total annual revenue with ETSA Utilities' reported annual revenue, again averaged over the review period, which was $14.25 million, as set out in figure 6-6.[161]

Thus, in broad summary, ESCOSA's regulatory task was to determine whether ETSA Utilities' prices were 'fair and reasonable', which it approached having regard to ESCOSA's assessment of ETSA Utilities' 'fair and reasonable' average annual revenue over a 4-year period.

Figure 6-6 ETSA Utilities' average annual revenue for public lighting excluded services during the period 1 July 2005 to 30 June 2009

Regulatory Year	ETSA Utilities revenue ($m)[17]
2005/06	13.73
2006/07	14.29
2007/08	14.65
2008/09	14.34
Average	**14.25**

Source: ESCOSA 2009, p. 37.

ESCOSA concluded:[162]

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161 ESCOSA Fair and Reasonable Determination 2009, pp 36-37.

162 ESCOSA Fair and Reasonable Determination 2009, p. 37.

> *While ETSA Utilities' revenues are slightly higher than the amount determined by the Commission, the Commission regards the difference as immaterial in the context of this Determination. As a result, [the Commission] determines that ETSA Utilities' public lighting excluded services charges for the period 1 July 2005 to 31 December 2009 are fair and reasonable for the purpose of the EDPD.*

As part of its processes, ESCOSA conducted an asset base roll-forward as part of determining 'fair and reasonable' average pricing levels for the period it was reviewing. It took the SKM 1998 starting value and rolled this forward using reported capex, disposals, contributions and gifted assets, inflation and an amount for depreciation. The detail of this roll-forward is set out in a table at Appendix 1 to ESCOSA's report.[163] However, in assessing whether we should use this roll-forward as the starting point for our opening RAB calculation, we think it is important to consider ESCOSA's analysis through the prism of ESCOSA's regulatory remit. There are two aspects of that regulatory remit which weigh against SAPN's argument that we should adopt ESCOSA's valuation.

First, ESCOSA's function under its regulatory scheme was not to 'lock-in' a closing asset value to serve as a basis for pricing decisions in future years. ESCOSA's task and approach contrasts with the position where a regulator makes an ex ante pricing or revenue determination which actually sets the level of revenues or prices for a regulatory control period - in the latter case the RAB established by the regulator at the beginning of the first regulatory control period is expected to endure (with appropriate roll-forward adjustments) for the initial and all future regulatory control periods. When the regulator determines a RAB value in those circumstances, it does so in the context of a regulatory scheme that envisages that the service will continue to be subject to ex ante price/revenue regulation in the subsequent regulatory period. It follows that the RAB values determined for one regulatory period will form the starting point for the next regulatory period; to do otherwise would arguably undermine the purpose of making the determination under the regulatory scheme. In our view, the same structural and purposive considerations do not apply when considering whether to apply values reached in one determination of a discrete pricing dispute (ESCOSA's determination) in a subsequent determination of a discrete pricing dispute undertaken under a different regulatory regime (the AER's determination).

Secondly, the 'fair and reasonable' test that ESCOSA was required to apply means that its regulatory task was not directed towards determining a precise RAB value that could be carried forward in subsequent regulatory decisions. SAPN submitted that the final value in Appendix 1 to the ESCOSA 2009 is the appropriate starting point for calculating a RAB for the current determination. SAPN states:[164]

> *The ESCOSA 2009 determination represented the first time that a building block model was applied with a continuous RAB roll-forward and depreciation allowance over the period of that roll-forward. Accordingly, this is the only appropriate starting point ('line in the sand') for any RAB calculations going forward and any assessment of recovery over the life of the assets.*

From the foregoing discussion it is clear that ESCOSA was doing a high-level assessment of costs – averaged over a multi-year period – to determine whether these lay within an acceptable range of the corresponding revenues for the same multi-year period. We do not

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[163] ESCOSA Fair and Reasonable Determination 2009, Appendix 1, referred to at para 83, p. 16.

[164] SAPN submission, August 2017, para 50, p. 9.

accept that ESCOSA's regulatory remit was to set an asset value for the purposes of locking in revenue allowances or capital recovery into the future.

Relying on a letter obtained from ESCOSA, SAPN contends that ESCOSA did intend for its decision to establish a 'long-term' sustainable cost base and depreciation rate.[165] ESCOSA's subjective intentions do not alter our reasoning, which proceeds from an understanding of the purpose of ESCOSA's task under the regulatory scheme governing its determination.

6.9.2 Aspects of ESCOSA are unclear and unpersuasive

From the material before us, we have formed the view that the reasoning underpinning several key aspects of ESCOSA's decision is unclear, such that those aspects of the decision are unpersuasive. This weighs against relying on ESCOSA's decision to provide the foundation for an opening RAB.

Firstly, the depreciation values in ESCOSA's asset roll-forward calculation are substantially lower than the depreciation figures provided by ETSA Utilities in the course of the state regulator's inquiries. This is illustrated by table 6.2, which shows a difference ranging from $1.27 million in 1998/99 to $2.08 million in 2007/2008.

ESCOSA's values may be expected to be lower than ETSA Utilities' values since the former are calculated on the basis of an average total asset life of 28 years, dating back to 1998 (as discussed in section 6.7.3). However the ESCOSA decision disregards ETSA Utilities' depreciation figures - as provided to the regulator as recently as 2008 - prior to the dispute period. ESCOSA's determination does not explain why it took that approach.[166]

Table 6-2 ETSA Utilities' reported depreciation compared with ESCOSA 'fair and reasonable' depreciation based on 28 year asset life ($ million, nominal)

	98/99	99/00	00/01	04/05	05/06	06/07	07/08
ETSA Utilities' submission	3.49[a]	3.76 [a]	3.96[a]	4.98[b]	5.21 [b]	5.42 [b]	5.70 [b]
ESCOSA 28-year depreciation[c]	2.22	2.35	2.53	3.04	3.24	3.39	3.62
Excess of 'reported' over 'approved' depreciation	1.27	1.41	1.43	1.94	1.97	2.03	2.08

Sources:
(a) SAIIR 2000, Box 3.1, p. 26. ETSA Utilities used these numbers in the asset roll-forward it provided to the SAIIR inquiry. SAIIR conducted a 'reasonableness check' on the numbers and accepted them as reasonable for the purposes of its inquiry: SAIIR 2000, p. 25.
(b) ESCOSA Statement of Issues 2008, table 1.1 Building block benchmark components 1 July 2005 to 30 June 2008 - depreciation, para 58, p. 10; ESCOSA 2008, table 2.3 ETSA Utilities' depreciation amounts (accounting v. regulatory) -

165 SAPN submission in response to the draft determination, para 12, p. 4, para 42, pp. 8-9 and Attachment A (letter from the Chief Executive Officer of ESCOSA dated 7 March 2019).

166 Cf SAPN submission in response to the draft determination, paras 36-41, p. 8.

regulatory depreciation, para 95, p. 17.
(c) ESCOSA Fair and Reasonable Determination 2009, Appendix 1: Asset roll-forward calculation.

Secondly, ESCOSA adopted an asset base substantially exceeding that put forward by ETSA Utilities. This was a result of ESCOSA backdating to 1998 ETSA Utilities' asset life revision. This is illustrated by table 6-3.

Table 6-3 ETSA Utilities' reported asset values compared with values in ESCOSA 2009 decision ($ million, nominal)

	2004/05	2005/06	2006/07	2007/08	2008/09	Average
ETSA Utilities' asset value[a]	29.85	28.33	26.12	23.70	-	-
ESCOSA's asset value[b]	-	40.46	40.85	40.96	40.71	40.74

Sources:
(a) ESCOSA Statement of Issues 2008, Table 2.1 - Building block benchmark components 1 July 2005 to 30 June 2008 - average asset values, para 71, p. 13.
(b) ESCOSA Fair and Reasonable Determination 2009, Table 2.1 - Commission's view on asset related costs - average asset values, para 112, pp. 20-21. The corresponding values in Appendix 1 - Asset roll-forward calculation differ marginally from the values in ESCOSA Fair and Reasonable Determination 2009 Table 2.1, but the difference is immaterial for present purposes.

A higher asset value beyond that reported by ETSA Utilities was an expected result of ESCOSA's decision to backdate to 1998 the revised asset life assumption of 28 years. ESCOSA in 2008 noted:[167]

> While reducing the depreciation rate will reduce the depreciation amount, it logically follows that the asset value will increase accordingly.

Beyond this, ESCOSA did not comment on the fact that its decision implied asset values in excess of the values in ETSA Utilities' submission and the values in the earlier regulatory decisions (SAIIR 2000 and ESCOSA's 2008 statement of issues) nor the implications of the backdating of the 28 years remaining life assumptions. It did not address the principle that a utility should be allowed to recover its investment once only. If ESCOSA's purpose in awarding a higher asset value was to achieve a smooth price profile in future[168] and slow down the erosion of the asset base,[169] we consider that those objectives do not justify the backdating to 1998 that ESCOSA brought about through its decision - namely, valuing the RAB in its determination for the 2005-2009 period as if ETSA Utilities had set its prices in the period 1998-2005 by reference to a depreciation rate calculated with a 28 year asset life assumption, when it had not. We do not consider that awarding a higher asset value in order to achieve either of those objectives, and, in particular, rolling forward that higher asset value into the 2010-15 regulatory period, would give effect to the regulatory principles in

167 ESCOSA Statement of Issues 2008, paras 111-112.

168 See section 6.7.3 above; see also SAPN submission in response to the draft determination, paras 38-39, p. 8.

169 See ESCOSA Statement of Issues 2008, para 103, p. 19; ESCOSA Fair and Reasonable Determination 2009, paras 109-110, p. 20.

circumstances where that would permit a service provider to recover more than the efficient costs of providing the service over the period of the access dispute.

6.9.3 Outcome if ESCOSA adopted

The material before us satisfies us that, from 1998 until 2005 at the earliest, a key parameter of ETSA Utilities' pricing was an expected average total asset life of 20 years. Since ESCOSA's roll-forward calculation assumes an average total asset life of 28 years since 1998, it is inconsistent with ETSA Utilities' earlier asset life assumption. For this reason, we consider that ESCOSA's asset base is overvalued.

If access charges for the dispute period are based on a RAB derived from the ESCOSA decision, those charges would exceed SAPN's efficient costs. The resulting price path would return more to SAPN than its initial investment over the asset's life and would be inconsistent with the regulatory principles (see section 6.8 above).

SAPN submitted to the contrary, that it is not established that deriving a RAB value from the ESCOSA 2009 decision would result in over-recovery. Whilst we have considered SAPN's submissions, the weight of the material satisfies us that adopting the ESCOSA value would result in access charges for 2010 to 2015 that exceed the efficient costs of providing the services.

Based on the information before us, we have concluded that SAPN's public lighting revenues in the period 1 July 1998 to 30 June 2005 reflected ETSA Utilities' assumption of a 20-year asset life. We make that assessment on the following bases:

- SKM assessed that ETSA Utilities' street lighting assets had an economic life of 20 years when valuing them in 1998. All subsequent calculations as to the value of the RAB have used SKM's valuation as a starting point (see section 6.7.1).
- SAIIR's finding that SAPN's charges were ‘fair and reasonable’ (as defined by the Treasurer's direction)[170] relied substantially on an assessment of ETSA Utilities' costs of providing the service. This construction included a cost element consistent with a 20-year straight line depreciation of the SKM RAB value determined as at 1 July 1998 and rolled forward to 30 June 2001.[171]
- Throughout the period between the SAIIR decision (which examined the year 2000/01) and the ESCOSA decision (which examined the period 1 July 2005 to 31 December 2009), SAPN asserts it charged the same tariffs from SLUOS services, on a per light basis, as the tariff approved by SAIIR.[172]
- It is true that, as SAPN argue, SAIIR did not use a building block method to **set** tariffs for the service.[173] However, SAIIR did use a construction to determine whether the projected revenue for 2000/01 (based on tariffs and number of lights at 1 July 2000) was 'fair and

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170 The South Australian Treasurer's terms or reference for the inquiry provided that '[i]n determining the fairness and reasonableness of [street lighting] tariffs [SAIIR] must take into account' eight particular matters, the first four of which directed SAIIR to the costs of providing the service, being '(a) the costs of providing the services […]; (b) the costs of complying with laws or regulatory requirements […]; (c) the return on assets used to provide the [services]; (d) the efficiency and cost effectiveness with which the street lighting services are provided'.

171 SAIIR 2000, p. 26

172 SAPN submission, August 2017, para 37, p. 10.

173 SAPN submission, August 2017, para 60(c), p. 15; SAPN submission in response to the draft determination, para 83, p.15

reasonable' in the sense of recovering no more than the efficient cost of providing street lighting services.[174] SAIIR determined a total revenue consistent with capital charges based on a 20 year asset life. It is reasonable to treat SAPN's revenues as returning capital to SAPN based on a 20 year asset life and straight line depreciation.

- In the years between 2001/02 to 2004/05, SAPN continued to charge the tariffs assessed as reasonable in 2000/01. Whilst we have considered SAPN's submissions to the contrary, we consider it is reasonable to treat total revenue collected by SAPN during this period as including a cost component based on a 20 year total asset life. SAPN submits that this requires an assumption that other costs would have remained constant in nominal terms, given it did not increase charges in this period.[175]
- Any reduction in the real value of total tariffs received between 2001/02 to 2004/05 might be expected to reduce the amount of depreciation that could be ascribed to those charges if other costs increased in nominal terms. It is unclear whether costs did increase in this period.[176] However, even if they did increase, it is likely that depreciation remained significantly above the level recoverable under the 28-year asset life, which ESCOSA assumed applied across this period.

As for the period 1 July 2005 to 30 June 2009, ESCOSA assessed ETSA Utilities' charges using a method including 28-year straight-line depreciation, and this is not disputed by either party.

In SAPN's submission in response to the draft determination, SAPN again contended that it is not reasonable for the AER to treat SAPN's revenue collected between 2001/02 and 2004/05 as inclusive of a cost component that reflected a 20 year asset life.[177] We have considered SAPN's arguments, but they have not caused us to change the preliminary conclusions we reached in the draft determination.

It is true that SAIIR assessed the reasonableness of SAPN's charges in one year only.[178] However, SAIIR's assessment for that one year was based on a 20 year asset life,[179] and SAPN used that assessment as its basis for setting prices in all subsequent years to 31 December 2005, making only minor changes to its charges.[180] Further, SAIIR stated that it had used a ''building block' approach to determine whether the level of revenue recovery at 1 July 2000 [was] fair and reasonable'.[181] In those circumstances, we consider that we should treat SAPN's street lighting revenue from 2000/01 to 2004/05 as if it included the cost components assessed by SAIIR, i.e. inclusive of depreciation based on the 20 year asset life

174 SAIIR 2000, p. ix, pp. 39-41.

175 SAPN submission 30 August 2017, para 60(e), p. 15.

176 It is unclear whether or not other costs should be regarded as having increased in nominal terms between 2000/01 and 2004/05 - e.g. SAIIR 2000, p. 29: 'The benchmark study indicated that ETSA Utilities' normalised cost should reduce by 16-17 per cent to fall to the average normalised costs. This would result in an operating and maintenance charge of $3.5 million (for 99/00) - at the lower end of the range provided for in the draft report. The SAIIR believes this target should be achievable with changed practices over two years, but not immediately'; Further example: SAIIR 2000, p. 50: 'The SAIIR believes that ETSA Utilities should be seeking ongoing cost reductions in the provision of street lighting services over time, and sharing these gains with councils or continuing to improve the level of service provided.

177 SAPN submission in response to the draft determination, paras 53-55, pp. 10-11.

178 SAPN submission in response to the draft determination, para 34 p. 7, para 53 p. 10.

179 See section 6.7.2 and figure 6.3 above.

180 See SAPN submission, August 2017, para 37 p. 10, para 60(e)(ii) p. 16; SAPN submission in response to the draft determination, para 88, p. 16.

181 SAIIR 2000, p. 17.

assumption.[182] We take the view that our conclusion is also supported by information we received from the parties following the release of the draft determination. In SAPN's submission in response to the draft determination, SAPN relied upon a letter that it obtained from the CEO of ESCOSA dated 7 March 2019. We considered that letter, annexed to SAPN's submission, and noted that it referred to two documents we had not previously seen: the ETSA Utilities submission to ESCOSA in response to ESCOSA's Statement of Issues paper, dated 11 September 2009; and the submission prepared by Trans-Tasman Energy Group on behalf of the PLCs and submitted to ESCOSA, dated September 2009. After we wrote to the parties seeking copies of these documents, SAPN provided a copy of the ETSA Utilities submission on 12 April 2019, and the PLCs provided a copy of the Trans-Tasman Energy Group submission on 4 June 2019. The ETSA Utilities submission does not support SAPN's argument; rather, it is more consistent with the AER's conclusion as to the appropriate asset life assumption.[183]

It is also true that SAIIR recommended that ETSA Utilities revise the 20 year asset life assumption for capital expenditure from 1 July 1998 onwards (new capital expenditure).[184] However, based on the matters we have explained above, we consider it is reasonable to treat SAPN's actual revenue in the relevant period as reflective of the 20 year asset life assumption for all assets, both old and new: those forming part of the asset base as at 1 July 1998, and new capital expenditure added from 1 July 1998 onwards. SAIIR's assessment is not the basis for our inference as to the manner in which SAPN recovered capital prior to 2005/06[185] - and it is only one of a number of factors in our reasoning.

SAPN again submitted that the 20 year asset life assumption is not reasonable because it hinges upon an assumption that SAPN's operating costs remained constant in nominal terms (and declined in real terms) following SAIIR's determination, and that assumption is 'unrealistic and not supported by the available facts'.[186] Relatedly, it also contended that SAIIR's opex estimation methodology is itself limited in its application, and that SAIIR likely would have estimated 'higher operating costs' if it had adopted a methodology 'in line with the more sophisticated methods now adopted by the AER'.[187] To support these arguments, it provided (in conjunction with Incenta) actual opex numbers and a model purportedly

182 Cf SAPN submission in response to the draft determination, para 54 p. 11.

183 See ETSA Utilities submission to ESCOSA dated 11 September 2009, p. 2 ('Public lighting tariffs today continue to be directly related to the tariffs that were set to reflect the revenue requirement allowed in the Commission's 2000 Final Report'),
Also see:

SAIIR, November 2000, Box 3.1 Asset roll-forward, p. 26.
ESCOSA, December 2008, Table 2.1.3, Building block benchmark components 1 July 2005 to 30 June 2008, p. 13.

ESCOSA, December 2008, Table 2.3.4, setting out ETSA Utilities' depreciation amounts, p. 17,

SAPN submission, September 2009, p. 20.
('For regulatory reporting purposes to date, ETSA Utilities has not applied the 20/28 year asset life split recommended by the Commission, instead continuing with the use of the straight line depreciation method based on a 20 year average asset life dating back to 1998').
See also the Trans-Tasman Energy Group submission, September 2009, Asset Base 1 July 2005, p. 3, which purports to use figures provides by ETSA Utilities and indicates that the roll forward of the asset base submitted by ETSA Utilities to SAIIR in 2000 was carried forward from 2000/01 to 2004/05.

184 SAIIR 2000, p. 25; SAPN submission in response to the draft determination, paras 78-80 pp. 14-15.

185 Cf SAPN submission in response to the draft determination, para 80 p. 14.

186 SAPN submission in response to the draft determination, paras 88-93, pp. 16-17.

187 SAPN submission in response to the draft determination, paras 83-87, pp. 15-16.

indicating that SAPN had under-recovered its opex from 2000/01 to 2004/05.[188] As a result, SAPN concluded, assuming a 20 year asset life would lead to SAPN 'materially under-recover[ing] its long-run efficient costs of delivering public lighting services'.[189]

As to SAPN's comments on the limitations of SAIIR's approach: SAIIR considered SAPN's opex using benchmarking as a tool to guide its considerations, but it did not exclusively rely on the benchmarking results,[190] and noted that those results should be 'seen as indicative only'.[191] Even with those caveats, however, SAIIR was able to determine an opex allowance for SAPN of $4.40 million as one component of the total SLUOS revenue allowance of $12.4 million.[192] While this represented a 9 percent reduction on SAPN's opex estimate for 2000/01, SAIIR considered this would be achievable with changed practices over two years.[193] SAPN's assertion that, if SAIIR had adopted a different opex assessment approach, its opex assessment would have been higher, is speculative. It does not necessarily follow that a different opex assessment would have resulted in a different assessment of depreciation costs. SAPN's submissions on this issue have not caused us to discount SAIIR's assessment from consideration as a factor in our analysis.

As to SAPN's analysis of its opex, we agree with the view SAPN expressed in an earlier submission that attempting a complete reconstruction of revenue and costs for the period 1998-2010 would require a 'review of all assumptions and methodological choices underpinning … past determinations, an exercise that would be fraught with difficulty and at high risk of error'.[194] A reconstruction of that kind is also outside the scope of this dispute: the parties have agreed that the matters arising for the AER's determination are those listed in section 2.4 above. Nor has the AER been asked to assess under- or over-recoveries in the period 1998-2010. We have not attempted such a reconstruction or assessment in determining what value of RAB as at 1 July 2010 should be used. Our approach has necessarily been more limited: we have concluded that rolling forward the RAB value determined by ESCOSA would be inconsistent with the regulatory principles, and that it is preferable to perform alternative RAB roll forward calculations based on the information we have obtained and our best judgment where uncontested figures are unavailable; and for these purposes, we have concluded that it is appropriate to treat SAPN's treated lighting revenue in the period prior to 2005/06 as inclusive of depreciation based on a 20 year asset life.

In conclusion, we examined SAPN/Incenta's modelling for the purpose of considering whether it undermines or changes our conclusion that the AER should adopt the 20 year asset life assumption. We have decided that this modelling does not alter our analysis.

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188 Incenta Economic Consulting, SA Street lighting – Comment on Draft Determination, March 2019, Figure 3.2, p. 19.

189 SAPN submission in response to the draft determination, para 94, p.17.

190 See, e.g., SAIIR 2000, p. 18 ('None of the decisions made by the SAIIR have been based solely on the benchmarking report, or indeed, any of the other tools in isolation'), cf SAPN submission in response to the draft determination, para 86, p. 15 (stating that reliance on the SAIIR methodology today 'would be seen as giving discordant weight to the results of a high-level benchmarking study').

191 SAIIR 2000, p. 22.

192 SAIIR 2000, table 3.5, p. 41.

193 SAIIR 2000, p. 29.

194 SAPN submission, August 2018, para 4(c), p. 3. See similarly SA Public Lighting Dispute, oral hearing transcript, 7.5.18, p. 24.

6.10 Why we have not followed the PLCs' approach

The PLCs proposed a method developed by Houston Kemp. It produces an opening RAB of $22.01 million as at 30 June 2010.[195]

The PLCs' proposed method commences with the SKM valuation at 1 July 1998, which is rolled-forward to 30 June 2010 by adjusting annually for inflation, capital expenditure and depreciation.

For inflation and capital expenditure, Houston Kemp adopts figures said to have been used in a roll-forward model developed by SAPN in the course of this dispute.[196]

For depreciation, Houston Kemp estimated an aggregate capital charge for each year and apportions this between return ON capital and depreciation. Houston Kemp based these estimates on information from the SAIIR and ESCOSA determinations, and on assumptions derived from those reports. Specifically, Houston Kemp calculated the return ON capital component using the rate of return used by the South Australian state regulator when assessing the reasonableness of public lighting prices.[197] The depreciation component is calculated as a residual after deducting the return ON capital component from the aggregate capital charge.[198]

In this way Houston Kemp purports to adjust the asset value to take account of the depreciation 'actually recovered' by ETSA Utilities.[199]

This method departs from the approach generally used under the RFM/PTRM or the building block model. Where Houston Kemp calculates depreciation as a residual, the generally used 'straight line depreciation' approach allows for the recovery of investment at a consistent rate over an asset's life.

Straight-line depreciation is the default position for calculating depreciation for regulatory and tax purposes in the RFM,[200] which is integral to the building block approach for calculating average annual revenues for standard control services set out in the PTRM. Although public lighting services are negotiated services, and therefore not legally required to be regulated under the RFM and the PTRM, the parties have agreed we should use the PTRM to determine appropriate public lighting charges for this dispute.

Much like the PTRM, the RFM is well established and understood and was developed to give effect to the NEO and other regulatory principles. Its application in this dispute to produce an opening RAB also requires fewer assumptions than the PLCs' proposed method. For example, the PLCs' method requires additional assumptions to be made as to (e.g.) the annual amounts SAPN actually recovered for capital costs between 1999 and 2010 and the method for calculating the required return on assets component of the annual capital

195 See table at Houston Kemp Economists, Expert Review of Balchin report - A report for HWL Ebsworth, 20 September 2017, p. 11.

196 Houston Kemp February 2017, footnote 37, p. 9.

197 Houston Kemp September 2017, p. 7. SAIIR applied a rate of return of 8.26 percent pre-tax real (SAIIR 2000, p. 23) while ESCOSA used 7.13 percent pre-tax real (ESCOSA Fair and Reasonable Determination 2009 p. 16).

198 Houston Kemp February 2017, pp. 8-14.

199 Houston Kemp February 2017, p. 8.

200 AER, Final Decision - Amendment, Electricity distribution network service providers roll-forward model handbook, 15 December 2016, p. 5.

costs.[201] Those additional variables create uncertainties in the method's application and outcome, and we consider that our choice of a method with those uncertainties to determine the opening RAB would not give effect to the regulatory principles.

The PLCs contend that the AER should not use the RFM to determine the opening RAB because there is ‘no regulatory precedent for using a roll-forward model … to determine an opening RAB at the commencement of a regulatory period when the regulated assets have not previously been subject to PTRM-based regulation’.[202] In determining the disputed issues between the parties, including the question of the correct opening RAB, our task is to adopt a methodology that we consider gives effect to the regulatory principles (see section 5 above). No regulator has previously had to determine an opening RAB in the precise circumstances with which we are faced in this case. We consider that the AER's RFM is the best tool available for our purposes, and do not consider it necessary for us to identify a particular ‘regulatory precedent’ supporting that choice.

The PLCs also argue that the AER's application of the RFM to determine the opening RAB is erroneous because it is ‘inconsistent with SAPN's previous pricing model’.[203] To be precise, SAPN did not use its financial model to ‘determine public lighting tariffs’;[204] rather, it contends that it used its financial model from 2012 onwards to cross-check the reasonableness of the public lighting tariffs it had previously charged (see section 5 above). In any event, the model SAPN used for that purpose was a historical version of the PTRM (see footnote 96 above). To determine this issue between the parties, we consider that it is appropriate for us to use the AER's RFM - which the AER has updated over time to reflect the best methodology available.

201 See the discussion in Incenta Economic Consulting, Determining the value of SA Power Networks' Public Lighting Assets - Report for SA Power Networks, August 2017, paras 81, 82, pp. 25-26.

202 PLC submission in response to the draft determination, paras 5(a) and 14, pp. 1, 3.

203 PLC submission in response to the draft determination, para 5(b) and 17-19, pp. 1, 3-4.

204 Cf PLC submission in response to the draft determination, para 17, p. 3.

7 Elevation Charge

7.1 Background

'Pole elevation' is the right to access power poles to attach public lights.[205] The 'elevation charge' in this dispute relates to this right of access, and is unrelated to the physical exercise of attaching lights to poles. The distributor owns the power poles. The issue is whether the distributor can charge a fee for allowing lights to be hung from those poles.

As noted in section 2.2.3, whether SAPN can properly include an elevation charge in its street lighting charges is one of the matters within the scope of the access dispute.

However, as a result of subsequent submissions of the parties, we consider the elevation charge is no longer in dispute. Nevertheless it is appropriate that we state our position on the matter.

7.2 Decision

An elevation charge will not be included in the cost base for determining appropriate public lighting revenues for the dispute period. SAPN no longer maintains that it has a right to recover an elevation charge. In any case we consider SAPN was not entitled to recover an elevation charge as an aspect of the service for the dispute period.[206]

7.3 Discussion

ETSA Utilities held the right to attach lighting facilities to its power poles by virtue of its ownership of the poles. The right was not granted to a third party such as the PLCs. There is a question whether ETSA/SAPN should be able to recover the costs of an elevation charge as part of its efficient costs of providing the service. As noted above, the PLCs dispute this.

In responding to the PLCs' initial submission, SAPN submitted:[207]

> *it is not necessary for the AER in this access determination to consider the inclusion of an access charge as a cost component in the prices charged for SLOUS during the 2010-15 period … SAPN's SLUOUS revenue for the 2010-2015 period was below the revenue requirement calculated by the PTRM, even without the inclusion of this cost component in the PTRM. Therefore it is not necessary for the AER to consider the elevation charge issue*.

The PLCs dispute SAPN's right to recover costs for an elevation charge. SAPN's submissions quoted above do not expressly disclaim this right. However SAPN has stated twice that the AER need not consider the elevation charge to determine this dispute. In so doing, SAPN did not reserve its right to recover an elevation charge. It submitted that considering its building block costs of providing SLUOS, without including an elevation charge, the AER would to come to the conclusion that SAPN's charges for SLUOS were

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205 ESCOSA Fair and Reasonable Determination 2009, para 155, p. 30.

206 Neither party made submission on the draft determination with respect to the elevation charge (PLC March 2019, para 3; SAPN March 2019, para 3.)

207 SAPN submission, August 2017, para 9(c), p. 4.

below its revenue requirements, calculated pursuant to the PTRM. In other words, even with the elevation charge, SAPN's SLUOS charges would be below the revenue requirement.

We consider it is appropriate to treat these submissions by SAPN as narrowing the matters in dispute between the parties, such that SAPN no longer maintains its right to recover an elevation charge in the access dispute. The legislative scheme for negotiated distribution services is one under which negotiated outcomes are preferred to adjudicated outcomes, and we consider we should exercise our discretion consistently with this preference.

For services classified as negotiated distribution services, the legislative scheme is designed to encourage users and service providers to negotiate terms of access, with the prospect of binding determination designed to encourage parties to reach negotiated agreement. Once an access dispute is notified, the AER may refer the dispute to non-binding alternative dispute resolution. That has happened in this case, with the ERP process narrowing the matters in dispute substantially.

We have had regard to this scheme in treating SAPN's submissions as not pressing a claim to recover an elevation charge. Hence, our primary determination on this matter is that it is no longer in dispute and does not require determination.

A service provider must be given a reasonable opportunity to recover the costs incurred in providing the service – the regulatory principles make this clear. However SAPN has not provided sufficient evidence or argument to establish that it incurred a material cost relating to pole elevation. Specifically:

- The cost of power poles (their construction and maintenance) is factored into SAPN’s Distribution Use of Service Charge
- It is not established that avoidable costs are greater than zero
- It has not been shown that an elevation charge would further the NEO through incentives, competitive headroom or other means.

Accordingly, if, contrary to our primary view that this matter is no longer within the access dispute, we are required to determine the matter, we determine that the elevation charge is to be excluded from our assessment of SAPN’s public lighting costs for the purposes of this determination. SAPN incurs no costs for which reimbursement can be justified in accordance with the regulatory principles.

8 Tax Asset Base

8.1 Background

The regulatory TAB is an input to the PTRM, which we are using to determine the appropriate level of public lighting revenues for the dispute period.

The regulatory TAB represents a regulator's estimate of the tax depreciation an entity is entitled to under Australian tax law. Where the regulatory TAB value is high, the PTRM will produce a relatively low level of allowed revenue, other things being equal. Conversely, if the regulatory TAB value is low, the PTRM will produce a relatively high allowed revenue value.[208]

8.2 Decision

The TAB value at 1 July 2010 is $15.96 million. This includes the value of contributed assets received by SAPN after the transition from a pre-tax regulatory framework to a post-tax framework, but does not include contributed assets received prior to this transition. This approach is consistent with previous regulatory determinations, including our price determination for SAPN for the 2010-15 regulatory control period.[209]

8.3 The parties' submissions

The main point of difference among the parties and the economic advisers concerns the inclusion or otherwise of the value of contributed assets - that is, assets gifted by developers - in the TAB. Including these assets produces a higher TAB, which in turn produces a lower level of allowed revenue under the PTRM (as outlined in section 8.1).

The PTRM for public lighting in the dispute period prepared by SAPN included an opening TAB of $14.30 million.[210]

Houston Kemp considered the opening TAB should be $28.26 million.[211] On the question of gifted assets, Houston Kemp advised:[212]

> The PLC has argued that the cost of income tax payable in relation to lighting assets gifted primarily from developer to SAPN should not be included in the allowed revenue to be recovered by SAPN. In contrast, I adopt SAPN's preferred approach, i.e., that these tax costs should be included in the TAB because it is common practice for Australian regulators to accept that capital contributions form a part of a business's assessable tax income in the year the asset is gifted, and for the asset subsequently to be included in the TAB and depreciated over the asset life.

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208 This is because a higher regulatory TAB means tax depreciation will be higher. This in turn reduces the regulated entity's estimated taxable income, and hence its estimated tax liabilities will also be lower. The lower estimated tax liability means the entity's costs are taken to be lower, translating – under a building block model where regulated revenue is set to equal expected costs – to a lower level of allowed revenue.

209 AER, South Australian Distribution Determination 2010-11 to 2014-15, May 2010, p. 162.

210 SAPN spreadsheet 'SAPN PTRM-PL 2010-2015 v2 0.xls' sheet 'WACC'

SAPN submission August 2017, para 67, p. 18.

211 Houston Kemp February 2017, p. 14.

212 Houston Kemp February 2017, p. 14.

Incenta Economic Consulting - an expert engaged by SAPN in this matter - commented on Houston Kemp's analysis, stating that the main difference between the opening TAB values proposed by Houston Kemp and SAPN arose from the treatment of customer contributions.[213] Incenta stated:[214]

> I understand that all parties agree that contributed assets can be included in calculation of tax depreciation for the purposes of calculating SAPN's actual payment of tax. The difference in position relates to whether it is reasonable to apply this practice when calculating the TAB for a firm that had until that time been regulated under a pre-tax WACC.

Incenta considered the more reasonable approach is to exclude from the opening TAB any assets contributed while SAPN was regulated under a pre-tax regulatory framework. Incenta argued this was correct in principle, and consistent with our treatment of SAPN's Direct Control Services when SAPN transitioned to a post-tax framework under the NER.[215]

Responding to Incenta's report, Houston Kemp posited that the guiding principle – that the TAB should reflect the expected tax depreciation of a benchmark efficient service provider – would be met by including the value of capital contributions in the TAB. Houston Kemp observed that, by contrast, SAPN's approach excluded capital contributions for the period from 1 July 1998 to 30 June 2010.[216]

SAPN relied on Incenta's report in submitting that the opening TAB value should be $14.31 million.[217] SAPN contended that including capital contributions in the opening TAB as proposed by Houston Kemp would be inconsistent with previous regulatory practices and determinations. SAPN's reply submission stated:[218]

> Incenta notes that the AER has previously accepted the proposition that past customer contributions should be excluded from the TAB when transitioning from a pre-tax WACC to post-tax WACC, on the basis that inclusion of these contributions could lead to an inappropriately low regulatory tax allowance. Incenta considers that there is no justification for not applying the same principles in this case.

Post the draft determination, SAPN agreed the TAB should not include assets gifted under the pre-tax framework.[219] While SAPN disagreed with setting aside the ESCOSA decision, it took the view that if the AER is minded to do so the TAB should be updated to reflect AER's modelling approach.

The PLCs stated it would made no submissions in relation to the draft determination as it relates to the TAB.[220]

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213 Incenta Economic Consulting, Determining the value of SA Power Networks' Public Lighting Assets - Report for SA Power Networks, August 2017, para 92, p. 29.

214 Incenta August 2017, para 94, p. 29.

215 Incenta August 2017, para 99, p. 30.

216 Houston Kemp September 2017, para 49, p. 8. This principle is consistent with NEL s. 6.5.3(2).

217 SAPN submission August 2017, para 67-69, p. 18.

218 SAPN submission October 2017, para 68, p. 11.

219 SAPN submission March 2019 pp. 18-19:

220 PLC submission March 2019, para 3.

8.4 Discussion

The position emerging from the parties' submissions is succinctly summarised by Incenta – the parties agree that contributed assets can be included in calculation of tax depreciation for the purposes of calculating SAPN's payment of tax, however the issue is how this applies where a firm transitions from a pre-tax to a post-tax regulatory framework. For SAPN, this transition occurred on 1 July 2010, when the AER became responsible for regulating SAPN's distribution services under the NEL and the NER.

Our framework and approach paper for our South Australian distribution determination for 2010 to 2015 set out our position for that decision in the following terms:[221]

Extract from AER framework and approach paper for SA distribution determination for the 2010-2015 regulatory control period

Capital contributions in the current and previous regulatory control period

Capital contributions are assessed as revenue for tax purposes, with a tax asset being created at the time of the contribution which can be depreciated over future years. Contributions received prior to the forthcoming regulatory control period will not be included in the tax asset base as:

- capital contributions have not been included in the RAB historically

- including capital contributions would create a shortfall given that past contributions have not been indexed, and

- the tax assets received from capital contributions compensated ETSA Utilities for the corporate tax incurred from receiving them.

Capital contributions during the forthcoming control period

Capital contributions are excluded from the RAB as the DNSP does not incur financing expenses from contributed capital. Capital contributions need to be included in the PTRM, however, as they are considered a form of revenue for tax purposes. Further, capital contributions are treated as depreciating assets for tax purposes, which reduces a DNSP's tax liability.

This followed advice we had commissioned from Ernst and Young on transitioning electricity distribution businesses from pre-tax to post-tax regulation. It was also consistent with the methodology we adopted to effect this transition for distribution networks service providers in NSW and the ACT.[222] ETSA Utilities' proposal was consistent with this approach.[223]

In the absence of any new perspectives on this issue, we consider it appropriate to maintain the position we adopted in our previous distribution determinations. It remains correct in

221 AER, Final framework and approach paper, ETSA Utilities 2010-2015, p. 102.

222 AER, Final framework and approach paper, ETSA Utilities 2010-2015, p. 102; For Ernst and Young advice see AER, Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009-2014, Preliminary positions, November 2007, p. 58.

223 AER, Draft decision, ETSA Utilities distribution determination 2010-2015, p. 251.

principle that contributed assets received by a regulated entity prior to its transition from pre-tax to post-tax regulation should be excluded from the opening TAB established for post-tax regulation purposes.

Although our approach is conceptually consistent with that proposed by SAPN, our opening TAB value differs slightly from SAPN's proposed value. This is because our RFM and PTRM depreciate new capex from the year after the capex is incurred – in turn, because capex incurred throughout a year is converted to end of year terms for inclusion in our models. However the models developed by SAPN and Incenta include a full year of depreciation for new capex in the year that the capex is incurred.[224]

224 Sapere Research Group, Modelling SAPN street lighting asset base and revenue 2010 – 2015, 22 January 2019, p. 10.

9 Corporate Overheads

9.1 Background

Corporate overheads are the costs relating to the organisational groups which support SAPN's operational functions, including finance, information technology, employee relations, OH&S and property services.

The issue is whether, and if so in what amount, the corporate overhead costs attributed to public lighting services over the dispute period should be adjusted in line with our decisions on the RAB and the TAB.

Post the draft determination the PLC made no submission on draft determination as it relates to corporate overheads.[225] SAPN accepts the AER's draft determination on corporate overheads.[226]

9.2 Decision

No adjustment is to be made to the quantum of corporate costs attributed to public lighting services in the dispute period based on our decisions on the RAB and TAB values.

9.3 Discussion

SAPN's cost allocation methodology apportions corporate overheads to various services based on the share of each service to SAPN's revenue from negotiated distribution services. Under this methodology, a service contributing a small share of SAPN's revenue is attributed a correspondingly small portion of corporate overheads, and vice versa. SAPN's cost allocation methodology was approved by the AER in 2009 and is not in dispute.[227]

Our decision on the RAB and TAB values leads to a reduction in SAPN's public lighting revenues for the dispute period - without more, in SAPN's cost allocation methodology, this reduction would reduce the quantum of corporate overheads attributed to public lighting services.

The PLCs submit we should make this adjustment. Their consultant, Houston Kemp, estimates that the allowance for corporate overheads should be reduced by $0.68 million in 2009/10 NPV terms, using the RAB and TAB values proposed by the PLCs.[228]

SAPN submitted there should be no adjustment to corporate overheads, even if our decision on the RAB and TAB values have the effect of reducing public lighting revenues, because:[229]

> *[…] it is not possible for SAPN to now go back and recover any amounts that would be notionally attributed to standard control services and other negotiated distribution services for the 2010-2015 period. Consequently, any ex post reallocation of corporate overhead costs would have the effect of denying SAPN a reasonable opportunity to*

225 PLC submission March 2019 para 3.

226 SAPN submission March 2019 para 3.

227 AER, Final Decision - ETSA Utilities Cost Allocation Method, February 2009

228 Houston Kemp February 2017, p. 17.

229 SAPN submission, August 2017, para 75, p. 19.

> *recover its efficient costs associated with the provision of standard control and negotiated distribution services in the 2010-2015 period […]*

We accept SAPN's submission. We further note that the quantum of any reallocation is likely to be relatively modest, that is, less than $0.25 million for the entire dispute period. This is estimated by reducing the corporate overhead value proposed by SAPN by the proportion by which the allowed revenue falling from our RAB and TAB values differs from the corresponding values proposed by SAPN. Even if we had been minded to accept the PLCs' position, the adjustment is not sufficiently material to warrant correction.

10 Discount rate for over-recovery

This section addresses the discount rate to be used to determine the present value of the overpayment of public lighting charges by the PLCs during the dispute period.

10.1 Decision

We will apply as the discount rate the nominal WACC applicable to SAPN, adjusted for outturn (i.e. actual) inflation. Table 10-1 sets out the applicable values.

Table 10-1 SAPN inflation adjusted regulatory WACC

FY	WACC value (adjusted to reflect outturn inflation) %
2010/11	10.55
2011/12	8.81
2012/13	9.74
2013/14	10.20
2014/15	8.49
2015/16	4.94
2016/17	5.80
2017/18	5.55
2018/19	4.92

10.2 Initial submissions

10.2.1 PLC initial arguments

The PLC's initial submission argued that the present value of any overpayments should be set using the regulatory WACC calculated by the AER for the 2010 to 2015 regulatory period, being 9.76 per cent. The PLCs submitted:[230]

> *The WACC […] reflects the regulatory assessment of SAPN's cost of funds; and insofar as SAPN has charged excessive street lighting tariffs historically, it has avoided a need to raise the corresponding amount internally.*

The PLCs further submitted:[231]

> *In our view, any over recovered revenues should be brought forward using the regulatory WACC as appropriate discount rate. This is consistent with regulatory practice of using WACC as the time value of money and would ensure that SAPN is neither rewarded nor penalised for the over recovery of public lighting revenues.*

[230] PLC submission, September 2017, para 51, p. 11.

[231] PLC, Submission post oral hearing 7 May 2018, 29 May 2018, para 21-22, p. 4.

10.2.2 SAPN initial arguments

SAPN submitted there should be no interest adjustment:[232]

> *To the extent that there is to be any adjustment for perceived overcharge in the [dispute period], SAPN maintains its view that there is no justification for compounding 'overcharge' amounts at the regulatory WACC - the regulatory WACC is not a cost faced by the PLC as a consequence of any overcharge. At most, the real value of any 'overcharge' […] should simply be removed from allowable revenue in future periods.*

10.3 Draft determination

In our draft determination we stated we would apply the nominal regulatory WACC which applied to SAPN from the commencement of the dispute period to the date upon which repayment is made. We considered this would, so far as possible, return the parties to the position each would be in had the overpayment not arisen. We stated that the true cost of a cash flow funded by debt must include both, the cost of the debt, and the equity capital to guarantee the return of that debt. This 'true cost' was best reflected by the regulatory WACC.[233] The WACC values for the relevant period are set out at Table 10-2 (Column 2).

10.4 Submissions following draft determination

10.4.1 SAPN response to draft determination

Responding to the draft determination, SAPN submitted it is a ‘well settled legal principle’ that the discount rate 'should be so as to restore the customer to the position they would have been in but for the overpayment.'[234] SAPN cited the decision of the High Court in Hungerfords v Walker[235] as authority for this principle.

SAPN submitted that applying a discount rate at the level of SAPN's regulatory WACC would not comply with this legal principle. According to SAPN, the WACC does not reflect the customer's opportunity cost of funds or losses incurred, so that using the WACC would create a windfall for customers - the WACC would provide a return that the PLCs would not have received had there been no overpayment. Further, SAPN submitted applying the WACC would be 'grossly unfair' in circumstances where SAPN (in its submission) did not cause the delay in resolving the dispute.[236]

SAPN argued there should be no discount rate adjustment apart from CPI. This was on the basis that the cost to the PLCs of funding the overpayment is minimal given that councils can raise funds from ratepayers[237] or, alternatively, borrow from the Local Government Finance Authority (LGFA).[238] The borrowing rates available to Councils from the LGFA are

232 SAPN submission, October 2017, para 75, p. 12.

233 AER Draft Access Determination - South Australia Public Lighting 2010 to 2015, February 2019, p. 62.

234 SAPN Submission March 2019, para 107.

235 (1989) 171 CLR 125

236 SAPN submission March 2019, p. 19.

237 SAPN submission March 2019, p. 20.

238 SAPN submission March 2019, para 114. The Local Government Finance Authority of South Australia is a body corporate established under state legislation offering financial services to local councils, including loans (principal and interest, interest only, and specially structured loans) and a range of deposit products.

set out at Table 10-2 below (Column 4). This, SAPN said, would reflect the 'opportunity cost' to the PLCs associated with the overpayment.[239]

In addition, SAPN argued that if the regulatory WACC is applied as the discount rate, the WACC must be adjusted for actual inflation over the period to which it applied.[240]

Incenta, an economic consultant engaged by SAPN, submitted that the discount rate should reflect the 'essentially low-risk' nature of the funds the PLCs have implicitly provided via the overpayment, such as (a) the PLC's own cost of borrowings, or (b) SAPN's cost of debt, either of which (a or b) should be adjusted for actual (i.e. outturn) inflation.[241] Incenta stated:[242]

> Furthermore, if the DNSP WACC or cost of debt is to be applied as a discount rate, then an adjustment is required for the difference between forecast inflation over the relevant period and actual inflation. This adjustment reflects the fact that the true, underlying regulatory interest rates are defined in real terms and vary with actual inflation.

10.4.2 PLC response to SAPN

The PLCs provided by leave additional submissions on this issue, being a report from Houston Kemp Economists dated 15 April 2019.[243] Houston Kemp stated that any discount rate that was less than a network service provider's cost of capital would be inconsistent with the efficient provision of services. Specifically:

- Whenever an access determination concludes that there has been an overpayment by customers, applying a rate less than the regulatory WACC would lead to the service provider over-recovering its efficient costs.
- Whenever an access determination concludes there has been an underpayment by customers, a rate less than WACC would lead to the service provider under-recovering its efficient costs.[244]

Houston Kemp submitted that it follows that adopting a discount rate less than WACC (where there has been an overpayment by customers) would create an incentive for network service providers to overcharge for negotiated services and delay negotiations. Houston Kemp stated:[245]

> […] adopting a discount rate that is less than the regulatory WACC means that networks can increase the rate of return on assets used in the provision of negotiated services by conducting themselves in a manner that is at odds with the NEO. Such conduct could include: approaching negotiations with a deliberate policy of over-

239 SAPN submission March 2019, p. 20.

240 SAPN submission March 2019, p. 20.

241 SAPN submission March 2019, Attachment B: Incenta Economic Consulting, SA Street lighting - comment on draft determination, March 2019, p. 8.

242 SAPN submission March 2019, Attachment B: Incenta Economic Consulting, SA Street lighting - comment on draft determination, March 2019, p.8.

243 Houston Kemp Economists, Further report of Greg Houston on SAPN's submission to the AER's draft decision, 15 April 2019.

244 Houston Kemp Economists, Further report of Greg Houston on SAPN's submission to the AER's draft decision, 15 April 2019, p. 4.

245 Houston Kemp Economists, Further report of Greg Houston on SAPN's submission to the AER's draft decision, 15 April 2019, p. 4.

pricing negotiated services; refusing to engage with customers in order to correct any potential over-pricing; and acting consciously to delay and/or extend the arbitration process.

Houston Kemp supported SAPN's submission that the regulatory WACC should be adjusted for outturn inflation—that is, adjusting for the difference between the forecast inflation embedded in the AER's nominal WACC and actual inflation outcomes. It submitted that this approach would be consistent with the broader regulatory framework administered by the AER, which provides for network service providers to earn an inflation adjusted nominal return on assets, protecting them from inflation forecasting risks.[246]

10.4.3 SAPN response to PLC

SAPN was given leave to reply briefly to the Houston Kemp report of 15 April 2019.[247]

SAPN rejected Houston Kemp's arguments about the incentive effects of a discount rate less than WACC, arguing it (SAPN) would have neither the incentive nor the ability to over-charge customers or prolong disputes. This is said to follow from the regulatory mechanisms applying to negotiated distribution services under the NEL and NER, which prevent a distribution service provider from engaging in such behaviour.[248]

SAPN also argued that using WACC would incentivise the PLCs to prolong the dispute, since the regulatory WACC is above the PLC's borrowing costs,[249] and further submitted that Houston Kemp's April 2019 report 'does not dispute' the legal principle relied on SAPN as to the appropriate discount rate.[250]

10.5 Discussion

In our view, the discount rate that best contributes to the NEO, the NDSC and the RPPs, is the rate which reflects the opportunity cost of the funds which have been overpaid. A discount rate above or below the correct opportunity cost will not promote efficient investment in electricity services or the long term interest of consumers with regard to price. When an over-recovery has occurred (as we consider to be the case):

- if the discount rate used for the adjustment is below the opportunity cost of the capital provided, the service provider will net over-recover in NPV terms and consumers will have paid more than the efficient costs of providing electricity services
- if the discount rate used for the adjustment is above the opportunity cost of the capital provided, the service provider will net under-recover in NPV terms and so consumers will have paid less than the efficient costs of providing electricity services.

SAPN submits that the correct discount rate is the opportunity cost for customers associated with any overcharge, or losses incurred by them. They consider there should be no compensation and at most the discount rate should be no higher than the PLC's borrowing

246 Houston Kemp Economists, Further report of Greg Houston on SAPN's submission to the AER's draft decision, 15 April 2019, p. 5.

247 SAPN submission 18 April 2019.

248 SAPN submission 18 April 2019, p. 4.

249 SAPN submission 18 April 2019, p. 5.

250 SAPN submission 18 April 2019, p. 5.

rate.[251] However, Houston Kemp for the PLCs argues that the opportunity cost of capital of the regulated service provider (i.e. the regulatory WACC) is the correct measure.

Hence, one key point of contention in discount rate submissions is whether the opportunity cost is to be assessed from the perspective of SAPN or from the perspective of PLCs ('customers' in the SAPN submission).

We also note that SAPN's economic advisor Incenta appears to agree the risk reflects the risk associated with the overpaid funds stating:[252]

> The relevant economic principle for the choice of discount rate is that the rate reflect the opportunity cost borne by the provider of the funds (in this case, the PLCs), for which the risk borne by the provider of funds is important.

Incenta later states [emphasis added]:[253]

> The risk the PLCs have borne *in providing funds to SAPN (in the form of over-payment)* is very different to what SAPN bears in providing distribution services…

Building on this Incenta position, the SAPN submission appears to equate the opportunity cost of funds received by the PLCs (from capital providers) with the opportunity cost of funds invested by the PLCs (in SAPN via overpayment). We consider the risk (and so the opportunity cost) borne by a PLC in providing these funds to SAPN is quite distinct from the risk associated with the provision of any funds to a PLC (that is, by a capital provider to a PLC). We agree with the Incenta statement (highlighted in the quote above) that the discount rate should reflect the risks the PLCs have borne in providing funds to SAPN—but this is the former transaction, not the latter.

The fact the PLCs receive most of their revenue directly in the form of rates from ratepayers, and can typically borrow at very low interest rates, is irrelevant to the risk associated with the overpayment to SAPN. As a result, the opportunity cost of lenders in providing debt to the PLCs does not reflect the opportunity cost facing the PLCs from the overpayment to SAPN. Equivalently, if instead the PLCs were borrowing money at very high interest rates to make their (over)payments, this would also be irrelevant to the risk of the implicit investment in SAPN, and we would not apply a much higher discount rate.

Our focus is on the opportunity cost of the transaction between the PLCs and SAPN. This provides for efficient investment, because SAPN neither under nor over recovers the efficient costs of providing electricity services.

We consider that well accepted finance theory supports the proposition that the opportunity cost of a given investment is the expected return that could be earned on another investment of equivalent risk.[254] The AER has looked at this and has had advice on this in the past. In a report examining the cost of debt for the AER in 2017 Associate Professor Partington and Professor Satchel stated:[255]

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[251] SAPN, SAPN's submissions in response to the Draft determination, P. 20.

[252] Incenta, SA Street lighting - Comments on Draft Determination, March 2019, P. 8.

[253] Incenta, SA Street lighting - Comments on Draft Determination, March 2019, P. 8.

[254] Brealey, Myers, Partington and Robinson, *Principles of Corporate Finance*, McGraw-Hill, 2000 (1st Australian Edition), p. 578.

[255] Graham Partington and Stephen Satchell, Report to the AER: issues in relation to the cost of debt, 9 April 2017, P. 13.

> the opportunity cost of capital is the rate of return that is currently offered in the capital market by securities of equivalent risk to the asset that is the subject of the NPV calculation. Investors have the opportunity to buy these securities in the capital market instead of investing in the asset. The return on the asset must have at least the same return as equivalent risk securities, otherwise investors will strictly prefer to invest in securities rather than the asset, since by so doing the investors get a higher return without taking extra risk. Thus it is the current rate of return from the securities having the same risk as the asset that gives the opportunity cost of capital.

Given we consider that the opportunity cost of capital is the risk associated with the overpayment to SAPN, the question is then what return on capital a party in the position of the PLCs might have achieved if, instead of overpaying SAPN, it had invested the (over payed) funds in an investment with an equivalent level of risk (equivalent to the risk facing PLC in providing the funds to SAPN). On this matter, SAPN submitted that:[256]

> Applying SAPN's regulatory WACC would create a windfall for customers. Customers would be given a return on the value [of] any overpayment – a return that they would not have received had there been no overpayment. There is no justification for this.

We disagree. We consider that, had there been no overpayment, the PLCs would have received a return, since they would have been able to instead invest those funds in another investment of equivalent risk.

To identify the opportunity cost in this matter, it is necessary to consider the level of risk associated with the PLC's claim to be repaid and to adopt the rate which best aligns with this risk level. Several options invite consideration.

First, the claimed overpayment could be conceived of as a loan from the PLCs to SAPN. In this case, the opportunity cost could approximately be reflected in SAPN's cost of debt. Returning the PLCs to the position they would have been in but for the overpayment requires (a) returning the overpaid funds, and (b) compensating the PLCs for the risk of having 'lent' the funds to SAPN. This risk is effectively the risk associated with SAPN defaulting and is captured in the nominal interest rate on SAPN's debt. We note that SAPN's own economic consultant, Incenta, consider that an appropriate discount could be 'the DNSP cost of debt'.[257]

However there are reasons to conclude that the risk attached to the overpayment is likely to be materially higher than SAPN's cost of debt. With a normal contractual debt there is a contractual obligation to repay the funds with interest, whereas in the present case SAPN disputes the existence of a debt and the obligation to repay will arise only upon determination. With contractual debt obligations there are also normally fixed time frames for interest and principal repayments, whereas in the present case both the timing of repayment and the interest rate are uncertain (even if repayment does take place).

The second option conceives of the overpayment as simply an average capital investment by the PLCs in SAPN. The overpayment displaced an equivalent amount of capital that SAPN would have otherwise sourced from debt and equity investors. The opportunity cost of this investment is best reflected by SAPN's WACC. This is because the SAPN WACC reflects the average opportunity cost of SAPN's capital. We cannot precisely identify which capital was displaced, but a reasonable proxy is to expect that it is in proportion to SAPN's

256 SAPN, SAPN's submissions in response to the Draft determination, P. 19.

257 Incenta, SA Street lighting - Comments on Draft Determination, March 2019, P. 8.

overall funding proportion between debt and equity holders. The WACC is a weighted average of the cost of SAPN's debt and equity, weighted by the market values of debt and equity SAPN's capital structure.

On balance, we consider SAPN’s WACC is the appropriate measure to reflect the risk associated with the PLC’s provision of the funds to SAPN via the overpayments. We consider the SAPN WACC best reflects the opportunity cost to the PLCs in providing the funds to SAPN. This measure (after inflation adjustment discussed later) also reflects the benefit to SAPN from avoiding the need to raise capital at its WACC via having access to the funds the PLC provided (via overpayment) over the period.

When considering the long term interests of consumers, we also have regard to the potential incentive effects that arise under either discount rate approach, if we were to consistently apply that approach over time. This is relevant to the long term interest of consumers in paying the efficient costs of providing electricity services.

As a baseline, we note that there are a number of factors outside the discount rate that influence any decision to over- (or under-) charge. This includes the likelihood of repayment being required, the type of capital the service provider avoids raising, and the expected costs (including legal costs) associated with any possible dispute.

Then we consider the incentive arising from our choice of discount rate. These incentive effects are not symmetrical. From the perspective of the service provider:

- Any discount rate **below** the true opportunity cost of funds would provide an incentive to overcharge, as the capital provided by customers is cheaper than they can raise in capital markets. There would also be an incentive to delay negotiations or resolution of an access dispute, as the delay increases the return (above the cost of capital) for the network service provider. If the access dispute is unsuccessful and the original pricing stands, the service provider retains the benefit of the over recovery.
- Any discount rate **above** the true opportunity cost of funds might, on first look, provide the network service provider with an incentive to undercharge, if they expected to recover an over-inflated amount from consumers in later years. They would have an incentive to delay negotiations on an access dispute in this case, as this increases the return (above the cost of capital) for the network service provider, so long as the access dispute was eventually resolved. However, if the access dispute never occurs (or is never resolved) the service provider wears the detriment of the initial under recovery. This risk appears material (no consumer would knowingly commence a dispute where they had been under charged). Hence, there is a limit to any potential incentive to undercharge in this case.

The key consideration from a customer perspective is whether, having been overcharged, they may have an incentive to delay resolution of a dispute.[258] If they expect to receive a return above the opportunity cost of capital associated with the overcharged amount, they have an incentive to delay. Conversely, if they expect to receive a return below the opportunity cost, they have an incentive not to delay. These effects should be broadly symmetrical.

[258] The customer has limited ability to influence the service provider’s decision to over (or under-) charge in the first place. If they are undercharged, they have no incentive to commence an access dispute.

Overall, our consideration of incentives also supports the use of the opportunity cost of capital of the overpayment to SAPN and not the average PLC borrowing cost (or an even lower amount).

In addition, supporting the use of the regulatory WACC is the consistent use of this measure in the regulatory setting to move cash flows through time. For example, at the end of each regulatory control period a process is undertaken to true-up any under-recoveries and over-recoveries of revenue in the period just ending, and to factor the net amount into the allowed revenue to be recovered in the subsequent regulatory control period - these true-ups are carried forward to the start of the new period at a rate equal to the network service provider's regulatory WACC. While this is not determinative, we note that consistent regulatory approaches are desirable because it creates greater certainty for both regulated firms and consumers on what will happen in a given situation (or in a given dispute).

We are not of the view that our approach is required to be consistent with the principles set out in Hungerfords v Walker, given that that case was concerned with the measure of damages applicable under tort and contract. Nor are we of the view that such an approach is desirable, given the task before us. Our task is to determine all matters in the access dispute, including the discount rate, in the manner we judge best contributes to the achievement of the NEO, and best gives effect to and applies the NDSC and the RPPs. Applying a discount rate below the regulatory WACC would result in SAPN recovering more than the efficient costs of providing electricity services, and so we do not consider that this would contribute to the achievement of the NEO. Nevertheless, to the extent that the decision in Hungerfords v Walkers stands for the proposition that a plaintiff is entitled to be compensated for the opportunity costs arising from money being withheld from it (with the question of how the opportunity costs are to be measured a question of fact to be determined in each case),[259] we consider that the approach we have adopted and described above is consistent with, and best gives effect to, that proposition.

We have had regard to all the factors described above and carefully considered the submissions of the parties in evaluating the different proposed discount rates. Consistent with our draft determination, we remain of the view that the opportunity cost of the overpaid funds is the correct measure, and this is best reflected by the regulatory WACC. Using this discount rate restores the PLCs to the position they would have been in, had the overpayment not occurred and the funds been invested in an alternative investment of equivalent risk. It also promotes efficient investment in networks assets by SAPN and efficient use of network services by its customers, because SAPN neither under nor over recovers the efficient costs of providing electricity services. Table 10-2 sets out the values for SAPN's WACC and its cost of debt in the relevant years.

Finally, we note that the difference between using SAPN's cost of debt and SAPN's regulatory WACC (after adjustment for inflation) is minor - in the order of 0.9 percent - as is the quantum of the overpayment calculated by either value ($12,795,826.47 at SAPN's cost of debt, and $13,008,154.01 at the inflation adjusted WACC).

[259] See Mason CJ and Wilson J at 144 (with whom Brennan and Deane JJ agreed at 152).

10.5.1 Inflation adjustment

SAPN and Houston Kemp (engaged by the PLCs) agree that if compensating for the time value of money at the regulatory WACC, this should be adjusted for the expected real return plus outturn inflation. SAPN also argue that if the regulatory cost of debt is used, this should also be adjusted for outturn inflation.

We support the parties' position on the inflation adjustment to the regulatory WACC. The AER's regulatory models provide a real return plus outturn inflation on the regulatory asset base. If the investment risk is taken to be equivalent to the regulatory WACC, the expected return as seen from the PTRM and the RFM is the expected real return plus outturn inflation. This is also consistent with the way money is moved through time in the PTRM for the final year true-up of under-recoveries and over-recoveries at the end of each regulatory control period, and charging adjustments arising from remittal recalculations and inflation error corrections.

However, while it is strictly not relevant to our decision given we are using the regulatory WACC (adjusted for inflation) for the discount rate, we note we do not consider an inflation adjustment would be appropriate if the regulatory cost of debt was used. This is because the expected return to providers of debt to a service provider is the service provider's nominal cost of debt (and not a real return on debt plus outturn inflation). It is equity providers who bear the risk associated with the indexing of the RAB in the PTRM and the risk of outturn inflation being higher or lower than forecast expected inflation over the period.

Table 10-2 Comparison of rates (%)

FY	SAPN WACC, nominal, adjusted to reflect outturn inflation (Final Determination)	SAPN WACC, nominal (Draft Determination)	SAPN cost of debt, nominal, not adjusted for outturn inflation	Council borrowing rate, nominal, adjusted to reflect outturn inflation[260]
2010/11	10.55	9.76	8.87	6.25
2011/12	8.81	9.76	8.87	5.98
2012/13	9.74	9.76	8.87	5.31
2013/14	10.20	9.76	8.87	4.94
2014/15	8.49	9.76	8.87	4.56
2015/16	4.94	6.17	5.28	4.18
2016/17	5.80	6.19	5.31	3.94
2017/18	5.55	6.18	5.29	3.82
2018/19	4.92	6.13	5.22	3.39

260 SAPN, Submissions in response to the draft determination, table 2, p. 20.

The discount rate for the three months from 30 June 2019 to 30 September 2019 is calculated in a manner consistent with the full year calculations above.[261]

[261] The nominal WACC adjusted for inflation is 1.48% for the three months. This is derived from the (annual) nominal WACC for 2019/20 of 6.09%, annual expected inflation of 2.50%, and three month outturn inflation from March 2019 to June 2019 of 0.61% (noting that this is the consistent extension of the same three-month-lagged inflation series used in prior years). If using the nominal SAPN cost of debt (not adjusted for outturn inflation), the discount rate is 1.26%, derived from the 2019/20 nominal cost of debt of 5.14%.

11 Form of recompense

This section provides our reasons for the form of recompense which is reflected in the draft determination set out in section 12.

11.1 The parties' views

At the oral hearings the parties were asked to give their views on what the outcome of this arbitration might be. The parties considered that 'determining this dispute' meant determining the prices that were applicable for the years 2010 to 2015. In terms of process, the parties contemplated that we would indicate our views on the disputed matters (whether through a draft determination or some other means), then give the parties the opportunity to negotiate a schedule of prices. In the event that the parties cannot agree, we would then make a final determination of prices based on a full building block methodology, including allocation of the maximum allowed revenue to specific customer classes with forecast demand et cetera.[262]

In a submission following the oral hearing, the PLCs proposed a method to determine final prices for the dispute period. The PLCs' method was to reduce the historical public lighting tariffs in an amount proportional to the difference between (a) the NPV of SAPN's recoverable revenue, calculated in accordance with the PTRM using the AER's input parameters, and (b) the NPV of SAPN's actual revenue.[263]

In their earlier submissions both suggested that, should we conclude that an over-recovery requiring correction has occurred, any recompense should take the form of an adjustment or offset against future public lighting tariffs. The PLCs submitted that:[264]

> *In the circumstances an appropriate course is for the AER to direct that the NPV of any overpayment in the 2010-15 regulatory [period] be determined and netted off against future public lighting tariffs in the manner indicated in the AER's letter of 2 August 2017.*

Our letter of 2 August 2017 referred to above sets out the procedure for the determination of the dispute. Contrary to the impression which could be left by the PLCs' submission, the letter does not indicate a position about the form of our final determination.

Similarly SAPN submitted that, should there be any adjustment for overcharging during the dispute period, the real value of the overcharge should be removed from future revenues, potentially across multiple years to avoid tariff volatility.[265]

Finally, SAPN put an alternative position that we should disregard any overcharging we find to have occurred during the dispute period on the basis that it was reasonable for SAPN to have charged prices in line with the ESCOSA 2009 decision. In its reply submissions, SAPN submits that:[266]

> […] any finding of error in the ESCOSA 2009 determination should only be factored into the determination of charges going forward.

[262] Transcript May 2018, pp 46-50.

[263] PLC submission, May 2018, para 15, p. 3.

[264] PLC submission, September 2017, para 51, p. 11.

[265] SAPN submission, October 2017, para 75, p. 12.

[266] SAPN submission, October 2017, para 74, p. 12.

Post the draft determination, PLC make no submission on draft determination's form of recompense.[267] SAPN did not make any comments in its submissions. .

11.2 Discussion

We do not accept SAPN's alternative submission that 'any finding of error in the ESCOSA 2009 determination should only be factored into the determination of charges going forward'.[268] Having concluded that the SAPN's public lighting charges exceeded its efficient costs, our judgement is that allowing the past over-payment to stand would not best give effect to the regulatory principles.

Putting SAPN's alternative submission to one side, the remaining submissions from both parties appear to be broadly aligned:

- Both parties contemplate that we will indicate our position on the disputed PTRM parameters and provide an opportunity for the parties to negotiate a schedule of tariffs applicable to the dispute period
- Both parties also appear to contemplate that any overpayment should be repaid over time as an adjustment to future revenues, rather than as a one-off payment.

We have indicated our position on the disputed PTRM parameters in this Draft Determination, and will afford the parties a reasonable opportunity to negotiate a final outcome.

However, in resolving this dispute, it is unnecessary for us to determine a schedule of tariffs for the period 2010 to 2015. While these tariffs precipitated the dispute, the dispute period has now passed, and the key issue is the quantum by which the PLCs have overpaid. We are able to calculate the total NPV of the overpayment without determining individual tariffs, and leave the apportionment of this sum to the PLCs to resolve among themselves.

We have no objection to the parties agreeing a mechanism to correct the overpayment over a period of time, for example through provision of a credit note or notes. However:

- the repayment mechanism must not involve an administering or supervisory role for the AER, and
- the repayment mechanism must stand apart from the distribution determination for SAPN's electricity distribution system for the 2020 to 2025 regulatory control period.

The parties will have a period of 28 business days from the date of our final determination to agree to, and advise us of the details of, a repayment mechanism meeting the requirements above. If the parties do not advise us accordingly within the 28 business day period, the NPV of the overpayment will be immediately repayable to the PLCs as at that date.

We are not persuaded by SAPN's submission that the overpayment should be deducted across multiple years to avoid tariff volatility.[269] Public lighting is one of a number of services provided by SAPN, and accounts for a relatively small proportion of its total revenue. While we have no objection to the parties making such an arrangement between themselves, we

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267 PLC submission, March 2019 para 3.

268 SAPN submission, 12 October 2017, para 74, p. 12.

269 SAPN submission, 12 October 2017, para 75, p. 12.

see no benefit in terms of the NEO and the other regulatory principles applying to this matter in imposing a schedule of repayments over time rather than a one-off payment.

12 Determination

As a result of our reasons for decision, pursuant to section 128 of the NEL the AER determines:

1. For the purposes of this dispute:
   (a) the opening Regulatory Asset Base (RAB) at 1 July 2010 is $34.79 million
   (b) the opening Tax Asset Base (TAB) at 1 July 2010 is $15.96 million
   (c) corporate overheads are not to be reallocated in consequence of our decision on RAB and TAB
   (d) elevation charges are not included in the public lighting cost base
   (e) the discount rate applicable to the over-recovered revenue for the dispute period is the regulatory weighted average cost of capital (WACC) applicable to SAPN, adjusted for outturn inflation, from the commencement of the dispute period until the date upon which repayment is made.
2. The present value of the over-recovery at 30 September 2019 is $13,008,154.01.
3. SAPN and the PLCs may propose additional orders by consent to determine the access dispute relating to the repayment of excess access charges paid by the PLCs.
4. If the parties do not propose an order by consent which is acceptable to the AER within 28 business days of this determination, or such later date as is agreed by the AER in writing, SAPN must thereupon pay the PLCs the present value of the over-recovery as at the date of this determination.