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Report prepared for the Australian Energy Regulator

The SA public lighting access dispute: the PTRM principles

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19 May 2018

sapere research group

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Glossary

AER	Australian Energy Regulator
DNSP	Distribution Network Service Provider
NDSC	Negotiated Distribution Service Criteria
NDSP	Negotiated Distribution Services Principles
NEL	National electricity law
NEO	National electricity objective
PLC	Public lighting customers
RAB	Regulated asset base
SAPN	SA Power Networks
SKM	Sinclair Knights Merz
TAB	Tax asset base

Introduction

1. We have prepared this report following instructions from the Australian Energy Regulator (AER). The AER is required to arbitrate in an access dispute between public lighting customers (PLC) and SA Power Networks (SAPN). PLC submissions to the AER are supported by expert reports from HoustonKemp Economists (HoustonKemp).[1] SAPN submissions are supported by expert reports from Incenta Economic Consulting (Incenta).[2]

2. In this first report, the AER has asked us to:

> *…set out the economic principles that the AER applies in developing the Post-Tax Revenue Model (PTRM), highlighting where Incenta and HoustonKemp have deviated from this approach.*

3. In addition, the AER has asked us to comment on the economic rationale for an elevation charge and whether this could be part of a PTRM approach. The elevation charge relates to a payment for access to stobie poles to attach public lights. An elevation charge has previously been included as part of the SAPN streetlight price although it is not relied on in their arguments for their current charges.[3]

4. We structure our report as follows:

    - We begin with the national electricity objective and the revenue and pricing principles in the National Electricity Law (NEL).
    - We review the negotiated distribution services criteria and principles applicable to an access dispute in relation to the price of a negotiated distribution service.
    - We outline the key features of the AER's Post Tax Revenue Model (PTRM) and how the objective, and the revenue and pricing principles, are given effect in the PTRM; we observe that a recovered capital method (RCM) would be inferior and be unlikely, in this case, to meet the NEL objective and principles.
    - We then comment on:
        - the approaches adopted by previous regulators to estimating the regulatory asset base (RAB)
        - consistency of alternative approaches to estimating the opening RAB at 1 July 2010 with the PTRM and its underlying principles
        - whether the general approaches taken by HoustonKemp and Incenta in their modelling deviate from the PTRM

1 HoustonKemp Economists, *Expert report of Greg Houston, A report for HWL Ebsworth*, 6 February 2017. HoustonKemp Economists, *Expert review of Balchin report, A report for HWL Ebsworth*, 20 September 2017.

2 Incenta, *Determining the value of SA Power Networks' Public Lighting Assets, report for SA Power Networks,* August 2017. Incenta Economic Consulting, *Determining the value of SAPN's Public Lighting Assets – response to the second report from Mr Houston and the submission of public lighting customers, Report for Gilbert + Tobin*, October 2017.

3 SAPN Submissions, 30 August 2017, paragraph 9(c).

– the appropriate tax asset base (TAB) at 1 July 2010

– any consequential reduction in overhead allocation as a result of changes to the opening RAB

– the economic rationale for an elevation charge and whether this could be part of a PTRM approach.

5. Our second report will provide a detailed assessment of the HoustonKemp and Incenta modelling against application of the PTRM.

6. In preparing this report, we have reviewed the following documents:

- AER, *ETSA Utilities cost allocation method: Final decision*, February 2009.
- AER, *Final Decision, SA Power Networks determination 2015-16 to 2019-20 Attachment 17 Negotiated services framework and criteria,* October 2015.
- AER, *Statement of principles for the regulation of electricity transmission revenues – background paper,* December 2004
- ESCOSA, *2005-2010 Electricity distribution price determination, Part A: Statement of reasons.*
- ESCOSA, *ETSA Utilities' public lighting excluded service charges: fair and reasonable determination*, December 2009.
- ETSA Utilities, *Cost allocation method*, September 2008.
- ETSA Utilities, *Negotiating framework*, July 2010.
- Incenta Economic Consulting, *Determining the value of SA Power Network's Public Lighting Assets: Report for SA Power Networks*, August 2017
- Incenta Economic Consulting, *Determining the value of SAPN's Public Lighting Assets – response to the second report from Mr Houston and the submission of public lighting customers, Report for Gilbert + Tobin*, October 2017
- Gilbert + Tobin, *Access dispute under Part 10 of the National Electricity Law between SA Power Networks and Public Lighting Customers, SA Power Networks' submissions*, 30 August 2017.
- Gilbert + Tobin, *Access dispute under Part 10 of the National Electricity Law between SA Power Networks and Public Lighting Customers, SA Power Networks' submissions in reply*, 12 October 2017.
- HWL Ebsworth Lawyers, *Access dispute under Part 10 of the National Electricity Law between SA Power Networks and Public Lighting Customers, The Public Lighting Customers' reply submissions*, 20 September 2017.
- HoustonKemp Economists, *Expert report of Greg Houston*, *A report for HWL Ebsworth*, 6 February 2017.
- HoustonKemp Economists, *Expert review of Balchin report*, *A report for HWL Ebsworth*, 20 September 2017.
- *Non-binding expert evaluation: Public Lighting Dispute in South Australia, Expert Review Panel Findings*, 9 September 2015.
- SAIIR, *Public street lighting tariffs: final report*, November 2000.

The National Electricity Law and Rules

The national electricity objective

7. The starting point for analysing the regulatory objective or principles underpinning the PTRM is the national electricity objective. The national electricity objective articulates the overall objective of the regulatory framework including the approach to setting a price for negotiated distribution services. The national electricity objective (NEO) is expressed in the National Electricity Law (NEL) as follows:[4]

> *The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to –*
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
>
> *(b) the reliability safety and security of the national electricity system.*

Revenue and pricing principles

8. In addition to the national electricity objective, the NEL specifies six revenue and pricing principles.[5] The AER "must take into account" the revenue and pricing principles in relation to an access determination for an "electricity network service".[6]

9. Public lighting has been specified by the AER to be a negotiated distribution service in South Australia.[7] The NEL states that a negotiated distribution service is an electricity network service.[8] Therefore, our understanding is that the revenue and pricing principles, set out in the NEL, are relevant to the AER arbitration of the SAPN street lighting dispute (and the reference to a 'direct control network service' in the revenue and pricing principles should be read as a reference to an 'electricity network service').[9]

10. Hence, the same principles as underpin the regulation of revenue and prices for direct control services should underpin the AER arbitration of the street lighting dispute. These principles are:[10]

    - A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in — (a)

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[4] National Electricity (South Australia) Act 1996, National Electricity Law – Schedule, section 7.

[5] Ibid, section 7A(2).

[6] Ibid, section 16(2)(a)(ii).

[7] AER - South Australia distribution determination 2010–11 to 2014–15, May 2010, Appendix A, page 283.

[8] NEL, section 2C.

[9] Ibid, section 16(3).

[10] NEL, section 7A.

providing direct control network services; and (b) complying with a regulatory obligation or requirement or making a regulatory payment.

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

11. The AER has developed its PTRM to comply with these principles when regulating revenue and prices for direct control services. As a matter of logic, the PTRM would also therefore comply with these principles if applied by the AER to determine prices for negotiated services.

Additional principles applying to an access determination

12. A dispute between a Distribution Network Service Provider (DNSP) and Service Applicant in relation to a negotiated distribution service is an access dispute for the purposes of Part 10 of the NEL.[11] The National Electricity Rules (NER) require that in determining an access dispute in relation to price, the AER must apply the Negotiated Distribution Service Criteria (NDSC) that are applicable to the dispute in accordance

[11] National Electricity Rules, clause 6.22.1(a).

with the relevant distribution determination.[12] In turn, the NDSC must give effect to, and be consistent, with the Negotiated Distribution Services Principles (NDSP) set out in the NER.[13] We interpret section 130 of the NEL to mean that the AER must give effect to the NDSC that currently apply, rather than to those applying in 2010-2015. If this interpretation is correct, the NDSC that are relevant to this dispute are those set out in attachment 17 of the 2015-2020 Determination for SAPN.[14] However, there appear to be no material changes in the relevant provisions between the 2010 NDSC and the 2015 NDSC for South Australia.[15]

13. The NDSC for SAPN that relate to price are set out in the table below, along with the NDSP that each criterion reflects and a brief comment on the relevance to the current issue. The first two criteria establish that the terms and conditions of access "should promote the achievement of the national electricity objective" and "must be fair and reasonable". A "fair and reasonable" price is defined in the NDSP as a price that complies with NDSP 1 to 7, which are equivalent to NDSC 5 to 11. Of these criteria, the one that we consider determinative in the current dispute is NDSC 5 (NDSP 1). This principle requires that prices reflect costs and are determined in accordance with the relevant Cost Allocation Method. As we note in the comment column of the table, the other criteria are either not relevant, or are not determinative because there is a range of prices that would satisfy the requirement.

12 National Electricity Rules, clause 6.22.2(c)(1).

13 NER, cl. 6.7.4(b) and cl. 6.7.1.

14 AER - Final decision SA Power Networks distribution determination - Attachment 17 - Negotiated services framework and criteria - October 2015

15 ETSA Utilities Negotiating Framework, July 2010, Schedule 2.

Table 1 Negotiated distribution service criteria and corresponding negotiated distribution services principles relating to price

NDSC	Corresponding NDS principle	Comment
1. The terms and conditions of access for a negotiated distribution service, including the price that is to be charged for the provision of that service and any access charges, should promote the achievement of the national electricity objective		There is likely to be a range of prices which could be assessed as promoting the national electricity objective. For the reasons discussed below, prices established using the PTRM would fall within the range of prices likely to promote the national electricity objective.
2. The terms and conditions of access for a negotiated distribution service must be fair and reasonable and consistent with the safe and reliable operation of the power system in accordance with the NER.	(9) The terms and conditions of access for a negotiated distribution service should be fair and reasonable and consistent with the safe and reliable operation of the power system in accordance with the Rules (for these purposes, the price for a negotiated distribution service is to be treated as being fair and reasonable if it complies with principles (1) to (7) of this clause)	There is likely to be a range of prices which could be assessed as compliant with principles (1) to (7) of the NDSP (or NDSC 5 to 11) and therefore deemed fair and reasonable. For the reasons discussed below, prices established using the PTRM would fall within the range of prices likely to be fair and reasonable.
5. The price for a negotiated distribution service must reflect the costs that a distributor has incurred or incurs in providing that service, and must be determined in accordance with the principles and policies set out in the relevant Cost Allocation Method.	(1) The price for a negotiated distribution service should be based on the costs incurred in providing that service, determined in accordance with the principles and policies set out in the Cost Allocation Method for the relevant Distribution Network Service Provider.	This NDSC and NDSP are at the core of the current dispute. When it approved the NDSC in 2015, the AER commented that to reflect the regulatory objective costs means efficient costs.

NDSC	Corresponding NDS principle	Comment
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.	(2) Subject to subparagraphs (3) and (4), the price for a negotiated distribution service should be at least equal to the cost that would be avoided by not providing the service but no more than the cost of providing it on a stand alone basis.	This NDSC states that the price of a negotiated distribution service must lie between the stand-alone cost of providing it and the incremental cost (or avoidable cost) of the service. The difference between stand-alone cost and incremental cost is the common costs incurred by SAPN to provide this and other services. The cost allocation method (referred to in NDSC 5) should guide the allocation of common costs between the relevant services.
7. If a negotiated distribution service is a shared distribution service that: i. exceeds any network performance requirements which it is required to meet under any relevant electricity legislation: or ii. exceeds the network performance requirements set out in schedule 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	(3) If the negotiated distribution service is the provision of a shared distribution service that: i. exceeds the network performance requirements (if any) which that shared distribution service is required to meet under any jurisdictional electricity legislation; or ii. exceeds the network performance requirements set out in schedules 5.1a and 5.1, then the differential between the price for that service and the price for the shared distribution service which meets (but does	This NDSC and NDSP relate to pricing network services provided to customers at a higher quality or reliability than required. It is not relevant here as the dispute is not about price variation for changes in quality.

NDSC	Corresponding NDS principle	Comment
distributor's incremental cost of providing that service (as appropriate).	not exceed) the network performance requirements under any jurisdictional electricity legislation or as set out in schedules 5.1a and 5.1 (as the case may be) should reflect the increase in the Distribution Network Service Provider's incremental cost of providing that service.	
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 distributor would avoid by not providing that service (as appropriate).	(4) If the negotiated distribution service is the provision of a shared distribution service that does not meet (and does not exceed) the network performance requirements set out in schedules 5.1a and 5.1, the differential between the price for that service and the price for the shared distribution service which meets (but does not exceed) the network performance requirements set out in schedules 5.1a and 5.1 should reflect the cost the Distribution Network Service Provider would avoid by not providing that service.	This NDSC and NDSP is essentially the reverse of NDSC 7 above, and relates to the pricing of network services provided at a lower quality than required. It is not relevant here as this dispute is not about price variation for changes in quality.
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	(5) 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	This NDSC and NDSP provide that all users must face the same price for a given service, unless there is a material cost difference in serving some customers. This does not appear to be relevant to the current dispute which

NDSC	Corresponding NDS principle	Comment
providing the negotiated distribution service to different Distribution Network Users or classes of Distribution Network Users.	service to different Distribution Network Users or classes of Distribution Network Users.	relates to the price charged to all public lighting customers (not a sub-set of customers).
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.	(6) The price for a negotiated distribution service should 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 the adjustment should reflect the extent to which the costs of that asset are being recovered through charges to that other person.	This NDSC and NDSP require prices to reflect the use of shared assets. Specifically, if an asset that is initially used to provide a negotiated distribution service is subsequently used to provide services to someone else, the price of the negotiated service should be adjusted to the extent that some of the asset value will be recovered from the other user. This principle does not appear relevant as the assets which are the subject of the dispute are not shared with other (non-PLC) customers.
11. The price for a negotiated distribution service must be such as to enable a distributor to recover the efficient costs of complying with all regulatory obligations or requirements associated with the provision of the negotiated service.	(7) The price for a negotiated distribution service should be such as to enable the Distribution Network Service Provider to recover the efficient costs of complying with all regulatory obligations or requirements associated with the provision of the negotiated distribution service.	This NDSC and NDSP specifically provide that efficient costs of complying with regulatory obligations are able to be recovered through prices. This principle does not appear relevant as the dispute is not about recovery of the costs of complying with regulatory obligations.

Source: AER - Final decision SA Power Networks distribution determination - Attachment 17 - Negotiated services framework and criteria - October 2015, pages 17-9 to 17-10; National Electricity Rules, paragraph 6.7.1

The PTRM

Objective is to set expected revenue to equal expected costs

14. The NEL requires the AER to perform its role as economic regulator in a way that "will or is likely to contribute to the achievement of the national electricity objective".[16] The Australian Competition Tribunal has summarised the economic foundation of the national electricity objective and the revenue and pricing principles as follows:[17]

> *Consumers will benefit in the long run if resources are used efficiently, i.e. resources are allocated to the delivery of goods and services in accordance with consumer preferences at least cost. As reflected in the revenue and pricing principles, this in turn requires prices to reflect the long run cost of supply to support efficient investment, providing investors with a return which covers the opportunity cost of capital required to deliver the services.*

15. *Ex ante* a firm must have an expectation that its investment will be profitable, or it will not invest.[18] This means investors expect the present value of future revenue to be no less than the present value of costs, where cost includes a reasonable risk adjusted return on the investment (the opportunity cost of capital).[19]

16. If the present value of revenue is equal to the present value of costs, then consumers pay no more than is required to attract the investment needed to efficiently provide the service. Hence, regulation that seeks to set the present value of revenue equal to the present value of efficient costs is in the long-term interests of consumers.

The building block method for determining revenue

17. Direct control services are classified as 'standard' or 'alternative' control services.[20] For standard control services, the way that the AER sets expected revenue to equal

[16] National Electricity Law, section 16(1)(a).

[17] Australian Competition Tribunal, *ElectraNet Pty Limited (No 3)*, [2008], paragraph 15, cited by the Federeval Court of Australia, *Australian Energy Regulator v Australian Competition Tribunal (No 2)*, [2017], paragraph 496, as principles "all parties appear to embrace".

[18] See for example Joskow, Paul L., 2005, *Regulation of natural monopolies*, Centre for Energy and Environmental Policy Research 05-008 WP, page 41, 54.

[19] HM Treasury Advisory Group, *Accounting for Economic Costs and Changing Prices: a report to HM Treasury by Advisory Group*, Vol 1, HMSO, London, 1986, paragraph 19 quoted in Commerce Commission New Zealand, 2016, *Input methodologies review draft decisions Topic paper 1: Form of control and RAB indexation for EDBs, GPBs and Transpower*, footnote 96.

[20] NER, paragraph 6.2.6.

expected efficient costs is through the PTRM, which reflects a building block model approach.[21] The building block model consists of two equations, the revenue equation (the PTRM) and an associated asset base roll forward equation (the RFM). These two equations are used to determine allowed revenues for the regulated firm for each year of a regulatory period. Putting to one side any incentive rewards or penalties and any smoothing of revenue over the regulatory period, these equations together ensure that the present value of the allowed revenue stream is expected to be equal to the present value of the expenditure stream of the regulated firm.

18. Expressed in its simplest form, the building block equations are as follows:

$$ARR = \text{return on capital} + \text{return of capital} + \text{opex} + \text{tax}$$

$$= (WACC \times \text{opening } RAB) + \text{depreciation} + \text{opex} + \text{tax}$$

and

$$\text{closing } RAB = \text{opening } RAB - \text{depreciation} + \text{capex}$$

where:

ARR = *annual revenue requirement*

WACC = *weighted average cost of capital*

RAB = *regulatory asset base*

opex = *operating and maintenance expenditure*

tax = *expected business income tax payable*

capex = *capital expenditure net of disposals*

19. Table 2 provides a description of these cost components:[22]

Table 2 Components of the building block model

Component	Description
Regulatory asset base (RAB)	The regulatory asset base is a stock of funds which reflects the total amount (in present value terms) which must be returned to investors in the future to compensate them for investments made in the past.

21 NER, paragraphs 6.3.2 and 6.3.1.

22 This table is adapted from AER, *Statement of principles for the regulation of electricity transmission revenues – background paper,* December 2004, page 15.

Component	Description
Cost of capital (WACC)	The cost of capital is the rate of return required by investors to induce them to commit funds to the network service provider (NSP). The required rate of return will depend on the riskiness of the returns to the NSP relative to other risky assets and the return on risk free assets. NSPs are funded using a combination of debt and equity. The required rate of return for the firm as a whole is the weighted average of the required rates of return on debt and equity, and is referred to as the weighted average cost of capital (WACC).
Depreciation (return of capital)	Depreciation is the flow of funds which returns to investors the 'capital' component of the funds they commit to the NSP (as distinct from the return on that capital). The total amount of depreciation of the firm must be equal to its total stock of capex over the life of the firm.
Operating maintenance and expenditure (opex)	The expenditures of the NSP which are not amortized over time – i.e., which are recovered in revenue in the year in which they are incurred.
Capital expenditure (capex)	The expenditure of the NSP which are amortised over time – i.e., which are added to the RAB, earn a return on capital as long as they are in the RAB, and which are recovered over time through the depreciation stream.
Tax	In the 'post tax' framework, the firm's tax liabilities are treated as a separate expenditure item.

Source: AER *Statement of principles for the regulation of electricity transmission revenues – background paper* (2004)

20. In addition to the components described in Table 2 above, the NER specifies that the building blocks in the PTRM are to include:[23]

- indexation of the regulatory asset base. The value of the RAB in each year of the regulatory period is increased by the expected rate of inflation to maintain the real value of the investment and, at the end of the period, the closing value of the RAB, after adjustment for actual inflation, then becomes the opening

23 NER, paragraph 6.4.3 (a)

value of the RAB for the next regulatory period. As a consequence, the rate of return in the revenue equation is set at the real rate; that is, the 'revaluation gains' are considered income and a component of the maximum allowed revenue

- the revenue increments or decrements (if any) for that year arising from the application of any efficiency benefit sharing scheme, capital expenditure sharing scheme, service target performance incentive scheme, demand management incentive scheme, demand management innovation allowance mechanism or small-scale incentive scheme
- the other revenue increments or decrements (if any) for that year arising from the application of a control mechanism in the previous regulatory control period
- the revenue decrements (if any) for that year arising from the use of assets that provide to provide certain other services.

21. The building block model specifies revenue for each year of a regulatory period, typically five years.[24] This is intended to create an incentive for the regulated firm to improve their efficiency, as they benefit from "beating" the forecast of costs.

22. It is important to draw a distinction between the expected return determined by applying the building block method and the return actually achieved by a regulated entity. A number of factors can influence the level of actual returns and the PTRM does not guarantee a normal return over the lifetime of a supplier's assets.

Application of the PTRM can meet the NEL and NER principles

23. The features of the building block model as applied in the AER's PTRM and associated roll-forward model for the RAB (RFM) are consistent with the revenue and pricing principles of the NEL (these principles are set out at paragraph 10 above), specifically by:

- allowing the DNSP a reasonable opportunity to recover the efficient costs of providing the service and complying with regulatory obligations
- providing incentives to promote economic efficiency
- allowing the DNSP to earn a return on their investment commensurate with risk.

24. The other revenue and pricing principles require the AER to have regard to the:

- regulatory asset base that has been previously adopted by a regulator or in the Rules

[24] Ibid.

- economic costs and risks of the potential for under or over investment in the distribution system
- economic costs and risks of the potential for under or over use of the distribution system.

25. The manner in which the AER implements the building block model, rather than the model itself, reflects these latter principles. The first of them, that regard should be had to previous values adopted for the regulatory asset base, is reflected in the RFM which impacts on the return on capital. The other two would usually be taken into consideration in the forecasting and parameter estimation processes.

26. The principles established by the NEL, and embodied in the AER's PTRM and RFM, are primarily concerned with establishing the *revenue* the service provider may target from its regulated services. The NDSC and NDSP provide further guidance on how the DNSP may set *prices* for specific services to identified customers (that is, negotiated distribution services). Meeting these principles requires additional considerations to those embedded in the PTRM and RFM (which are concerned with determining efficient revenue).

27. In particular, the prices charged to a particular customer (or set of customers) must:[25]
    - reflect the costs incurred in providing the service
    - be the same for all customers receiving the same service
    - be adjusted over time if the assets (the costs of which are being charged to that customer) are used to provide services to other customers
    - be between avoided and stand-alone costs.

28. The last bullet point, that prices should lie between the avoidable cost of providing the negotiated service and the standalone cost of providing those services, highlights that the definition of "costs" is not necessarily straightforward. There is a high degree of common costs in the electricity distribution sector; that is, costs which are not specific to a particular service or customer. As a result there is likely to be a significant difference between the avoidable (or incremental) cost and the standalone cost of a specific service.

29. If the PTRM and RFM are being used to determine revenue, and hence a price for a negotiated service, then the inputs to the models should be specified in a manner consistent with the DNSP's cost allocation method. This approach would be consistent with the NDSC and NDSP.

RCM would be inferior to the PTRM

30. In its *Financial Reporting Guideline for Non-Scheme Pipelines* (December 2017), the AER set out a recovered capital method (RCM) for estimating the return of capital

[25] AER - Final decision SA Power Networks distribution determination - Attachment 17 - Negotiated services framework and criteria - October 2015, page 17-10

recovered by a service provider. This method rearranges the building block revenue equation as follows:[26]

depreciation (return of capital) = *revenue – (return on capital + opex + tax)*

31. Rather than a forward looking projection, the RCM formula would be applied looking backwards. In its *Explanatory Statement* the AER explained that the approach was set out for non-scheme pipelines because:[27]

> *There is currently little publically available information on the costs incurred by service providers and the relationship between these costs and the prices charged for services. The purpose of financial reporting is not to allow prospective users to carry out a detailed bottom-up cost of service analysis, but rather to provide prospective users with an indication of the costs associated with providing services, the revenue earned and return on assets generated by the pipeline.*

32. In the current case, there is publically available information on the capital costs incurred by SAPN in providing street lighting (for example, the ESCOSA roll-forward value[28] and the Sinclair Knight Merz valuation of the RAB cited in the SAIIR November 2000 determination [29]).

33. Relative to the cost estimates which can be obtained by applying the PTRM and RFM methods to these cost bases, an RCM would provide a much less accurate estimate of the return of capital or other elements of the capital cost of providing street lighting. For example, as discussed in paragraph 21 above, forward-looking revenue regulation, as applied to DNSPs in Australia, creates incentives for the regulated firm to improve efficiency, as the DNSP benefits from "beating" the forecast of costs. The RCM formula set out in paragraph 30 above, applied looking back, would inaccurately attribute any such efficiency gain as additional return of capital.

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26 Australian Energy Regulator, *Financial Reporting Guideline for Non-Scheme Pipelines*, December 2017, page 19.

27 Australian Energy Regulator, *Financial Reporting Guideline for Non-Scheme Pipelines: Explanatory Statement,* December 2017, page 20.

28 ESCOSA, *ETSA Utilities' public lighting excluded service charges: fair and reasonable determination*, December 2009.

29 See for example SAIIR, *Public street lighting tariffs: final report*, November 2000 sections 3.3.2 and 3.3.3.

Regulatory asset base and depreciation

34. We have read the reports prepared by HoustonKemp and Incenta and completed a preliminary review of their spreadsheet models as provided to the AER.[30] From this initial qualitative assessment, there appear to be two key factors which would cause the results from their respective modelling to differ – this qualitative assessment will be reviewed and confirmed from detailed modelling in our second report. These two key factors are:

- the choice of the initial asset value
- the assumed asset lives (and hence depreciation profile).

35. In combination, differing treatment of these two factors lead to a different opening value of the asset base (RAB) at 1 July 2010, and hence different estimates of the return on and of capital (the largest component of the building block for SAPN street lighting charges).

The opening asset base

36. Applying the PTRM requires an opening value for the RAB. This value would then be rolled forward by adjusting the value for inflation, adding capital expenditure (less disposals) and deducting depreciation.

37. Initial RAB values are effectively locked-in under most current Australian regulatory frameworks, with little or no scope to reopen past valuation decisions. These initial valuations are rolled forward with adjustments made for depreciation and to account for new capex and asset disposals. In the electricity sector, this 'lock in and roll forward' approach originated from the AER's Statement of principles for the regulation of electricity transmission revenues (2004).

38. In concept, the initial locked-in value could be determined based on the historic cost of the assets, or an independent valuation of the assets. In practice, a lack of historical records has resulted in the AER adopting an independent valuation as the initial 'locked in' value for DNSP's RABs. Where assets are revalued this is often done using a depreciated optimised replacement cost methodology, which measures the cost of replicating the service in the most efficient way possible. This valuation method is consistent with the NEO, since it reflects the cost structure of an efficient entrant.

39. It is important to establish a certain and consistent approach to valuing the RAB because it affects a significant component of revenue and prices through the return of and on capital. This is the rationale provided by the AER in adopting its

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30 Op cit, footnotes 1 and 2.

approach of locking in the opening RAB, rather than re-valuing the assets in each year of a regulatory period and in moving to the next period.[31] Rolling forward an initial locked in value is also consistent with the revenue and pricing principle in the NEL which requires regard to be had to values of the regulatory asset base adopted in a previous regulatory determination or decision.[32]

40. There appear to be two practical options available to the AER in considering the appropriate estimate of the opening RAB as at 1 July 2010:

- roll forward the closing RAB for 2008/09 contained in the 2009 Essential Services Commission of South Australia (ESCOSA) determination[33]
- roll forward the 30 June 1998 Sinclair Knight Merz (SKM) valuation of the RAB.[34]

41. There are other possibilities. A new independent valuation could be undertaken, but that would be costly. A RAB value is also available from the 1999/2000 South Australian Independent Industry Regulator (SAIIR) determination.[35] But as that value is neither an independent valuation nor the latest regulatory determination, there is no obvious economic rationale for selecting it.

Asset life assumptions

42. For the two options for estimating the initial asset value, the following asset life assumptions would need to be considered to determine the opening asset value as at 1 July 2010:

(a) If the ESCOSA asset value were adopted, then no additional decisions about asset lives would be required to determine the opening asset value for the 2010-2015 period.

(b) If the SKM asset value were adopted and rolled forward using the AER's RFM then a decision would be required as to the useful life of the assets included in the SKM valuation.

Previous RAB values and asset lives

43. The parties variously rely on three previous estimates of the value of the public lighting assets in South Australia. Each of these estimates was associated with an

31 AER, Statement of principles for the regulation of electricity transmission resources – background paper, 2004, page 40.

32 National Electricity Law, section 7A(4).

33 ESCOSA, ETSA Utilities' public lighting excluded service charges: fair and reasonable determination, December 2009.

34 The SKM valuation is referred to in the ESCOSA decision (ibid) and an earlier SAIIR report (SAIIR, *Public street lighting tariffs: final report*, November 2000).

35 SAIIR, *Public street lighting tariffs: final report*, November 2000.

assumption about the useful life of the assets and their average age. These are set out in Table 3.

Table 3 Estimated public lighting asset values and lives

	SKM	SAIIR	ESCOSA
Initial asset base (depreciated)	$37.07m	$37.07m (SKM)	$37.07m (SKM)
Useful life	20 years	20 years	28 years
Remaining life	Approx. 11 years	11 years	18 years
Useful life of new capex	N/A	28 years	28 years
Closing asset base (date)	$37.07m (30 June 1998)	$35.78m (30 June 2001)	$40.18m (30 June 2009)

Source: SAIIR, *Public street lighting tariffs: final report*, November 2000; ESCOSA, *ETSA Utilities' public lighting excluded service charges: fair and reasonable determination*, December 2009.

44. Two of the estimates were made by state regulators in the context of a dispute between the distributor and public lighting customers.[36] Both of these decisions, in 2000 by SAIIR and in 2009 by ESCOSA, took as their starting point an independent valuation of public lighting assets prepared by Sinclair Knight Merz (SKM).

45. The SAIIR decision explains that SKM assessed SAPN's street lighting assets to have a gross value of $66.13m and a written down value of $37.07m at 1 July 1998.[37] SAIIR states that SKM assumed the assets had a 20 year average useful life.[38] Based on these figures, we estimate that the assets were on average approximately 9 years old at the time of the SKM valuation, with 11 years of useful life assumed to be remaining.

46. We explain the regulators' estimates of asset value and asset lives in more detail in the remainder of this section. We also briefly describe our understanding of the framework within which each estimate was made.

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[36] At the time of both previous regulators' decisions, SAPN was called ETSA Utilities. It changed its name in 2012.

[37] SAIIR, 2000, Box 3.1, page 26.

[38] SAIIR, 2000, page 24.

SAIIR, 2000

47. In 2000, the Office of the South Australian Independent Industry Regulator (SAIIR) undertook an inquiry into the "fairness and reasonableness" of street lighting tariffs that were charged by the electricity retailer AGL SA. The company's tariffs were bundled retail tariffs that included charges for all components of the street lighting supply chain.[39] The SAIIR used a "'building block' approach to determine whether the level of revenue recovery at 1 July 2000 is fair and reasonable."[40]

48. At the time of the SAIIR decision (2000), the Electricity Pricing Order 1999 (EPO) set out the tariffs and adjustment formulas for prescribed transmission and distribution services for 2000 to 2005 and for prescribed retail services until full retail contestability in 2003.

49. Public lighting was deemed in the EPO to be an excluded distribution service. A more 'light handed' approach was specified in the EPO for excluded services. For public lighting, the EPO set a maximum retail tariff that could be charged by AGL SA until 1 January 2003. The public lighting distribution service charge levied by the DNSP, ETSA Utilities, was one component of the public lighting retail tariff and comprised approximately 60% of the tariff. Other components of the tariff were prescribed services, with regulated tariffs.

50. As the other components of the tariff were fixed under the EPO, the SAIIR's inquiry focused on the excluded distribution service charge by ETSA Utilities.[41] The SAIIR also recognised that because the total tariff was fixed under the EPO, any cost reductions in street lighting services were unlikely to be passed on to consumers, at least until full retail contestability commenced on 1 January 2003.[42]

51. To assess a fair and reasonable depreciation charge, SAIIR requested information about asset lives from ETSA Utilities. This information suggested a weighted average life of 28 years.[43] SAIIR noted that the depreciated value determined by SKM was based on a 20 year asset life and considered that if the asset life were to be changed the SKM depreciated value used as the opening asset value would also need to be changed.[44,45]

52. SAIIR's approach to assessing whether ETSA Utilities' charge for public lighting services was fair and reasonable was based in part on benchmarking tariffs and costs with other distributors. It found that 20 years was commonly used in other

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39 SAIIR, 2000, page ix.

40 SAIIR, 2000, page 17.

41 SAIIR, 2000, page 4.

42 SAIIR, 2000, page 4.

43 SAIIR, 2000, page 23-24.

44 Ibid.

45 We discuss the treatment of a change in asset life part way through its life in the section "Effect of changing asset lives".

jurisdictions and there was no empirical evidence that it was an unreasonable assumption.

53. SAIIR concluded that the asset life assumption for existing assets should remain at 20 years, but for new capital expenditure it should be revised.[46] The data presented shows that new capital expenditure was assumed to have an average life of 28 years.[47]

54. The asset value for 30 June 2001 is derived from the SKM assessment at 1 July 1998; this has been indexed using the CPI. Capex is added based on the assumption of mid-year expenditure and is therefore escalated at a rate of half the CPI in the year of expenditure. Depreciation is deducted based on the asset life assumptions noted, adopting an 11 year remaining life for assets in the SKM valuation. We note that there appears to be an error in the SAIIR estimate of depreciation for 1999/2000, which allows for depreciation on 1998/99 capex twice. This error is carried forward into the estimate of 2000/01 depreciation and hence the written down values for both years.

55. A written down (depreciated) asset value as at 30 June 2001 of $35.78m was deemed to be fair and reasonable by the SAIIR for the purposes of its inquiry.[48]

ESCOSA, 2009

56. The Essential Services Commission of South Australia (ESCOSA) was established in 2002.[49] ESCOSA took over the functions and body corporate of the SAIIR.

57. In December 2008, ESCOSA prepared a Statement of Issues in relation to whether ETSA Utilities' street light charges were fair and reasonable. At the same time ESCOSA directed ETSA Utilities and street lighting customers to undertake commercial negotiations to attempt to settle the relevant charges. The Statement of Issues was intended to assist in that process. A settlement was not reached and ESCOSA subsequently issued a determination of the fairness and reasonableness of ETSA Utilities' street light prices in December 2009.

58. The ESCOSA determination relates to whether charges for the period 1 July 2005 to 1 December 2009 were fair and reasonable, as was required by the 2005-2010 Electricity Distribution Price Determination.[50]

59. ESCOSA's objective was to determine a long term sustainable price. It considered that this was one that would allow ETSA Utilities to recover costs, based on a reasonable assumption about the rate of change of prices, such as CPI indexation.[51]

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46 SAIIR, 2000, page 25.

47 SAIIR, 2000, Box 3.1, page 26.

48 SAIIR, page 26.

49 https://www.escosa.sa.gov.au/about-us/about-us

50 ESCOSA, 2009, paragraph 2.

51 ESCOSA, 2009, paragraphs 95(b) and 102.

ESCOSA explicitly describes the "re-calibration" of depreciation to ensure a price path that is sustainable in the long run.[52]

60. The analytical framework and baseline values developed by the SAIIR for its decision were considered by ESCOSA in its determination.[53] However, ESCOSA noted that provided it assessed ETSA Utilities' prices to be fair and reasonable, it was not relevant whether there were other prices that could also be considered fair and reasonable or that someone considered other prices to be *more* fair and reasonable.[54]

61. ESCOSA tested each element of revenue to determine whether it met the fair and reasonable test.

62. ESCOSA adopted the SKM assessment as the opening RAB value for 1 July 1998.[55] It rolled this value forward using "reported actual capital expenditure, disposals, contributions and gifted assets, inflation escalation, and appropriate depreciation amount."[56] ESCOSA explained that "to encourage efficient investment, as a minimum, ETSA Utilities' allowance should include an amount that represents a return of the invested capital, at a rate that provides for the recovery of the assets in the future."[57] ESCOSA was assessing an efficient long-run depreciation cost that would result in a smooth price path, and reflect the cost structure of a new entrant. It determined that ETSA Utilities' depreciation calculation methodology was an appropriate basis for a fair and reasonable public lighting charge.

63. Depreciation was determined assuming a 28 year useful life for all assets. Appendix 1 of the ESCOSA report states that the remaining useful life of assets that were part of the SKM assessment of value was assumed to be 18 years at 1 July 1999.[58] This is consistent with the SKM assumption that the assets were approximately 9 years old on 1 July 1998. However, from the data it appears that the roll forward actually assumed an 18 year remaining life at 1 July 1998.[59]

64. The opening depreciated RAB value is rolled forward using these assumptions to give a closing RAB at 30 June 2009 of $40.18m.[60]

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52 ESCOSA, 2009, paragraph 103.

53 ESCOSA, 2009, paragraph 53.

54 ESCOSA, 2009, paragraph 54.

55 ESCOSA, 2009, paragraph 77.

56 ESCOSA, 2009, paragraph 78.

57 ESCOSA, 2009, paragraph 92.

58 ESCOSA, 2009, Appendix 1.

59 Ibid. This observation is based on the relative value of depreciation on 'old' assets compared to the inflation-adjusted written down value of those assets. ESCOSA has re-calculated a gross value of existing assets at 1 July 1998 based on the SKM written down value and ESCOSA's asset life assumption.

60 Ibid.

Consistency of the options with the PTRM

65. In this section we discuss the consistency of the options identified for setting the initial value of the RAB and the asset life assumptions with the PTRM and the principles underlying it. We also comment briefly on the approaches adopted by HoustonKemp and Incenta.

Roll forward the ESCOSA RAB value

66. The ESCOSA closing RAB for 2008/09 took as its starting point the initial written down value estimated by SKM ($37.07m).[61] This value was then rolled forward by ESCOSA using actual capital expenditure, disposals, contributions and gifted assets, inflation indexation and deducting a depreciation allowance calculated using a 28 year useful life for all assets.[62]

67. Under the AER's RFM, consistent with the NER asset roll forward for direct control service as described in Schedule 6.2., the asset base is indexed and increased by actual capex net of capital contributions and reduced by depreciation. The RAB at time t, where p_t is actual inflation, is thus given by:

$$RAB_t = RAB_{t-1}(1 + p_t) + (Capex_t - Disposals_t) - depreciation_t$$

68. The roll forward employed in the determination of the ESCOSA RAB is thus consistent with the AER's RFM. Adopting the ESCOSA RAB value would also be consistent with the revenue and pricing principle that requires regard be had to the regulatory asset base adopted in a previous regulatory decision or determination.[63] The AER has adopted the approach of using the previous regulatory asset base in other instances.[64]

69. If the ESCOSA RAB rolled forward is adopted as the opening asset value for 2010/11, these values could be taken directly into the AER PTRM. However, NER requires that the sum of the real value of depreciation over the economic life of an asset should be equivalent to the initial value of the asset.[65] Given that ESCOSA assumed that the assets had an economic life of 28 years, this requirement would not be met by roll forward of the ESCOSA RAB if revenue over the early years from

[61] ESCOSA, 2009, op. cit., paragraph 77.

[62] Ibid, paragraphs 78 and 110.

[63] NEL, section 7A(4).

[64] For example, the NER specifies that the RAB for South Australian distribution system as the opening RAB value from the ESCOSA 2005-2010 Electricity Distribution Price Determination (see NER paragraph 6.2.1(c) and ESCOSA *2005-2010 Electricity Distribution Price Determination, Part A – Statement of Reasons,* April 2005, page 124). The AER required NSW distributors to determine their public lighting RAB by using the 2004 opening RAB from IPART's previous determination (AER, *New South Wales distribution determination 2009-10 to 2013-14*, 28 April 2009, page 356). This was "on the basis that it is consistent with previous regulatory decisions and the depreciation that has occurred." (AER, *New South Wales draft distribution determination 2009-10 to 2013-14*, 21 November 2008, page 330.)

[65] NER, paragraph 6.5.5(b)(2).

1998/99 was set by application of the AER's RFM on the basis of the assets having an economic life of 20 years.[66]

Roll forward of the SKM valuation

70. If the 1 July 1998 SKM valuation were adopted as the initial lock-in value, additional decisions would be required in relation to asset lives and the calculation of depreciation, in rolling the asset value forward to 1 July 2010.

71. As shown at paragraph 43 above, application of the RFM requires knowledge of the indexation rate, net capex and depreciation. Indexation is straightforward and we understand that actual net capex can be determined from the relevant regulatory accounts. The remaining issue would therefore be depreciation. We have reproduced the relevant provision from the NER in an appendix.

72. The purpose of depreciation is to allocate the capital cost of the assets across their useful life. This allocation of cost promotes efficient use of the assets by promoting a smooth price profile over time as well as efficient investment (by facilitating the recovery of efficient capital costs). This outcome is consistent with the revenue and pricing principles and the NEO.

73. South Australia's public lighting assets have been subject to different useful life assumptions over time as shown in Table 3 above.

Effect of changing asset lives

74. When the useful life of an asset is deemed to have changed part way through its life, normal accounting practice is to depreciate the remaining value of the asset over the revised remaining life. This normal accounting practice is consistent with regulatory precedent and our reading of the PTRM and RFM handbooks.[67]

75. In 1999, the Independent Pricing and Regulatory Tribunal (IPART) provided a report to the Premier of NSW on electricity pricing.[68] In this report they set out their view on the appropriate approach to a change in the useful life of an asset.[69] At the time, distributors were arguing that where an asset life changed, the change should be applied retrospectively, increasing the asset value to the level it would have

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[66] In its November 2000 decision that SAPN's charges were fair and reasonable, the SAIIR adopted a 20 year useful life for the assets that were in the SKM 1998 asset valuation.

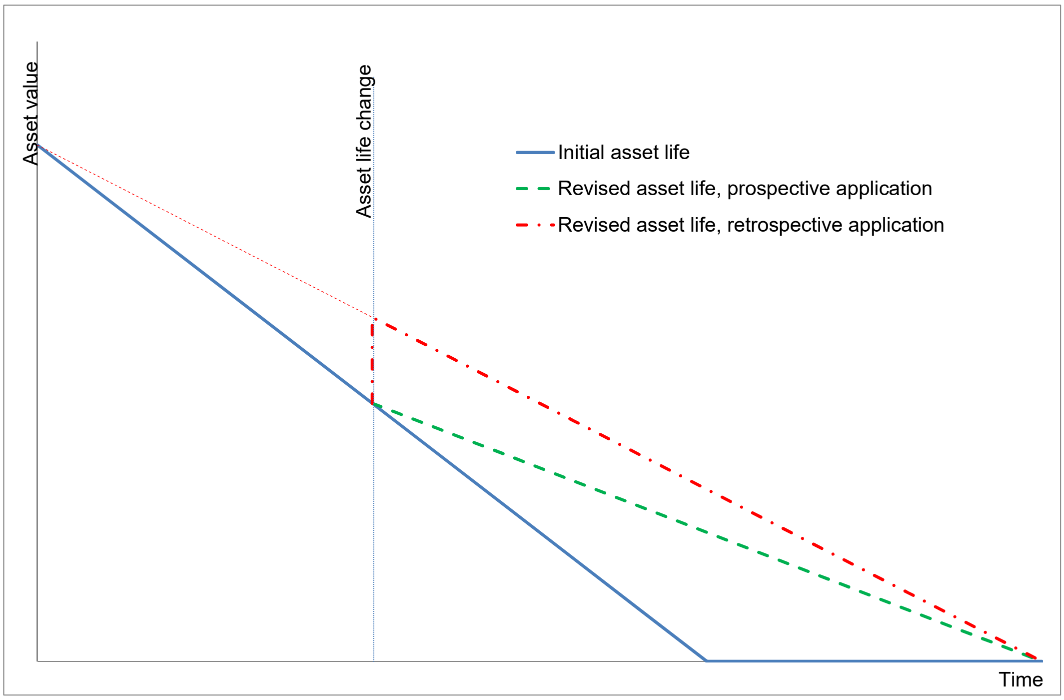
[67] AER, Electricity distribution network service providers, Post-tax revenue model handbook amendment, 29 January 2015 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/post-tax-revenue-models-transmission-and-distribution-january-2015-amendment; AER, Electricity distribution network service providers Roll forward model handbook amendment, 15 December 2016, https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/roll-forward-model-distribution-december-2016-amendment ; the New Zealand Commerce Commission, Input Methodologies (Consolidated April 2018), 2.2.7, 5.3.9.

[68] Independent Pricing and Regulatory Tribunal of New South Wales (IPART), Pricing for electricity networks and retail supply, Report, Vol 1, Rev99-5.1, June 1999.

[69] Ibid, pages 100-102.

been had the revised useful life been applied initially.[70] This is illustrated in Figure 1 below.[71]

Figure 1 Illustration of revising asset life of partially depreciated asset



Source: Sapere Research Group

76. IPART's view was that a retrospective application was inappropriate; the change in asset life should be applied on a prospective basis (see Figure 1). They noted a retrospective application resulted in long-term customers being required to pay for both the depreciation on the initial investment and the valuation increment. A prospective change "leaves the utility indifferent in present value terms".[72]

77. More precisely, the net present value is the same once the return on capital is taken into account. Figure 2 shows a simplified analysis that demonstrates this outcome. The analysis is based on a single asset, which is initially depreciated over 10 years; after 5 years the asset life is revised to 15 years. The stacked columns show the impact on the depreciation profile and the return on capital of applying prospectively the revised asset life compared to the profile for the initial asset life. The height of the columns represents the asset cost (return on and of capital) in each year under the two scenarios.

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70 If this approach had been followed, the revaluation gain should have been accounted for as income, as was the practice in previous ODRC revaluations where asset lives were changed.

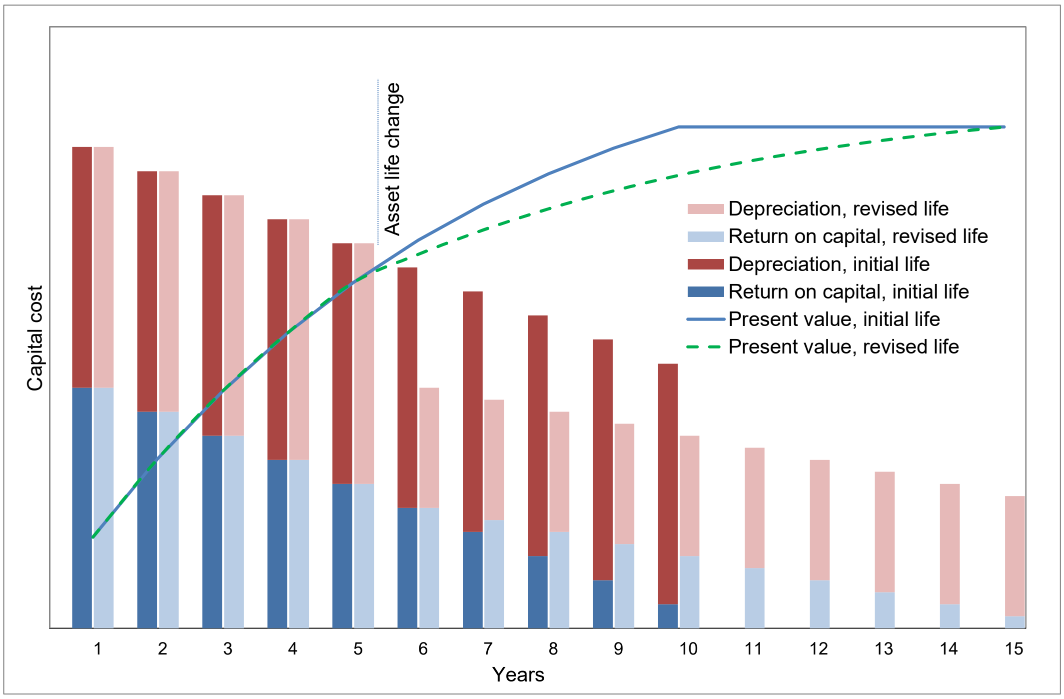
71 This is based on Figure 8.2 in IPART, op. cit., page 102.

72 Ibid, page 101.

78. The lines illustrate the cumulative present value of the asset-related costs. The blue line shows that using the initial asset life assumption the maximum present value is reached in year 10, at which time the asset is fully depreciated and no further revenue is derived from it (the line is extended to year 15 for the purposes of the illustration). The green line relates to the scenario where the asset life is revised at the start of year 6. In this case the total present value of the asset costs at year 15, when the asset is fully depreciated, is the same as the present value under the initial asset life assumption. This result illustrates IPART's conclusion that the utility is indifferent to the change in asset life, applied prospectively, in present value terms.

Figure 2 Asset-related costs, initial and revised life

Prospective application, simplified



Source: Sapere Research Group

79. IPART also noted that accounting convention applied a change in asset life in prospective terms.

80. IPART went on to apply this approach to distributors in NSW in their 2004 determination:[73]

> *The changes in asset lives will apply on a prospective basis only — that is, the changes will apply from 2004/05. The Tribunal will not recalculate depreciation for the 1999-04 regulatory period.*

[73] IPART, NSW Electricity Distribution Pricing 2004/05 to 2008/09 Final Report, Other Paper No. 23, June 2004, page 65.

81. In 2009, the AER was responsible for the economic regulation of NSW distribution services. In its determination it allowed distributors to change the remaining asset lives used to determine the depreciation schedules.[74] While the application of these changes to asset values is not specifically discussed, there is no change to the opening RAB as a result of the updated remaining asset lives. As such the AER appears to have applied an approach consistent with IPART's prospective method.

82. The AER's PTRM and RFM handbooks are also consistent with the prospective approach. To model depreciation, the PTRM inputs include:

- opening asset values for each asset class, which "are manually sourced from the closing asset value for each asset class as determined in the RFM"[75]
- the average remaining life of the asset. The RFM handbook explains: "The remaining lives of each asset class are … based on the economic lives of the assets as at the start of the current regulatory control period. These values should be consistent with those contained in the PTRM used in the current building block determination for the DNSP."[76]

83. No link is made between the economic lives at the start of the current regulatory control period and the opening asset value, the consequence is that if the asset lives are reset, they are used prospectively only.

84. Finally, we note that the prospective approach also satisfies paragraph 6.5.5(b)(2) of the NER which requires the sum of the real value of depreciation over the economic life of an asset to be equivalent to the value of the asset when it was initially included in the RAB.

Incenta approach

85. Incenta argues that the opening value of the RAB for the 2010-2015 period "should be determined by applying the roll-forward method for the 2005-2010 period, as determined by the ESCOSA".[77] As noted above, the roll forward employed in the determination of the ESCOSA RAB is consistent with the AER's RFM. Adopting the ESCOSA RAB value would also be consistent with the revenue and pricing principle that requires regard be had to the regulatory asset base adopted in a previous regulatory decision or determination.[78]

86. However, as the ESCOSA assumed that the assets had an economic life of 28 years, the NER requirement that the sum of the real value of depreciation over the

74 AER, New South Wales distribution determination 2009-10 to 2013-14, Final Decision, 28 April 2009, pages 214-215.

75 AER, Electricity distribution network service providers, Post-tax revenue model handbook amendment, 29 January 2015, page 13.

76 AER, Electricity distribution network service providers Roll forward model handbook amendment, 15 December 2016, pages 7-8.

77 Incenta Economic Consulting, *Determining the value of SA Power Networks' public lighting assets*, August 2017, paragraph 45 .

78 NEL, section 7A(4).

economic life of an asset be equal to the initial value of an asset would not be met if revenue over the early years from 1998/99 was set on the basis of the assets having an economic life of 20 years.[79]

HoustonKemp approach

87. HoustonKemp accepts that estimation of the opening RAB as at 1 July 2010 should be based on the SKM valuation.[80] However, HoustonKemp attempt to calculate the depreciation for each year after the valuation date as a residual after firstly estimating the total of the capital charges for the year (that is, depreciation plus return on capital) and then deducting an estimate of the return on capital.[81] The estimates of the total capital charge and the return on capital are obtained from varying sources and reflect a number of assumptions. The estimates of depreciation as residuals may therefore differ significantly from the depreciation amounts which would result from applying the AER's RFM.

88. The Houston Kemp approach would also have the effect of disturbing past regulatory decisions, which allowed SAPN to set prices (revenue) at a particular level during the relevant period. Such undoing of the past is not desirable as it would increase the cost of capital to SAPN.

Summary: Options for establishing opening RAB

89. The discussion above identifies two options for estimating the opening RAB for 2010/11 consistent with the AER RFM:

- roll forward the closing RAB for 2008/09 contained in the 2009 Essential Services Commission of South Australia (ESCOSA) determination
- roll forward the 1 July 1998 Sinclair Knight Merz (SKM) valuation of the RAB.

90. There are two variants of the second option as the SKM valuation could be rolled forward assuming either:

- asset lives of 28 years for all assets over whole period (essentially replicating or checking the ESCOSA roll forward)
- different asset life assumptions - assets existing at the time of the SKM valuation could be rolled forward initially with a 20 year life assumption to 30

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79 In its November 2000 decision that SAPN's charges were fair and reasonable, the SAIIR adopted a 20 year useful life for the assets that were in the SKM 1998 asset valuation.

80 HoustonKemp Economists, *Expert report for Greg Houston, A report for HWL Ebsworth*, 6 February 2017, page 8.

81 It could be argued that this approach reflects the RCM method but in that case the estimate of depreciation for each year should be derived from the building block equation restated as *depreciation =[revenue –(opex + tax)] - return on capital.* (as stated at paragraph 30 above) and applied with known amounts for revenue, opex, tax, and return on capital for each year. Note that the equation for depreciation, given on page 10 of the Houston Kemp report, is incorrect.

June 2005 (reflecting the SAIIR assumption) and then the remaining undepreciated value rolled forward assuming 28 years to 2010 (reflecting the ESCOSA assumption). New assets would be rolled forward assuming 28 years as this assumption was consistent for both SAIIR and ESCOSA.

Tax asset base

91. The issue with regards to the tax asset base (TAB), concerns the tax treatment of contributed assets, i.e. assets that were gifted by developers to SAPN. HoustonKemp argues that contributed assets should be included in the TAB,[82] and Incenta argues that these should be excluded prior to 2010 because SAPN was regulated under a pre-tax WACC model during this period.[83]

92. The issue arises because of the different way in which tax is determined in a model that uses a pre-tax WACC compared to one that uses a post-tax WACC. In a post-tax model, tax is an output. The closing TAB is equal to the previous year's closing TAB plus net capital expenditure (capex less disposals) plus contributed assets less depreciation. This treatment reflects the actual tax treatment of contributed assets: contributed assets are treated as revenue when they are first received (and therefore liable for tax) and there is a matching stream of tax deductions arising from the depreciation expense.

93. In a post-tax model, the business is compensated for the tax liability when the asset (revenue) is received and the subsequent stream of deductions reduces taxable income over the life of the asset as it is depreciated.

94. A pre-tax WACC model applies a different approach; in this model, tax is an input. Tax is estimated based on the net operating revenue forecast and the business is compensated accordingly. Capital contributions are ignored, implicitly assuming that the stream of depreciation deductions offsets the initial liability. This approach ignores the opportunity cost of funds used to pay the initial tax liability.

95. If past contributed assets were to be included in the tax asset base when a business moves from a pre-tax WACC regulatory approach to a post-tax WACC approach then the business would have incurred the tax cost of the assets but would not receive the benefit of the remaining depreciation deductions arising from those assets. This would occur because tax deductions would increase, reducing the tax building block (output) and hence allowed revenue.

96. The AER agreed with ETSA Utilities that contributed assets received when a pre-tax regulatory model was in place should not subsequently be added to the TAB when the business transitions to a post-tax model. Contributed assets received *after* the transition should be added to the TAB however.[84]

97. As such, we agree with the approach adopted by Incenta. They outline the reasoning described above in their report, concluding that requiring SAPN to include assets gifted prior to 2010 in their TAB would result in their remaining value as tax

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82 Houston Kemp, op cit, page 14.

83 Incenta, op cit, page 29.

84 ETSA Utilities, *ETSA Utilities Revised Regulatory Proposal 2010-2015*, 14 January 2010, page 209; and AER, *South Australia distribution determination 2010-11 to 2014-15*, May 2010, page 163.

deductions being passed back to customers. This would create an unfunded cost, because SAPN would not receive the full stream of deductions to offset the tax liability that was incurred prior to 2010. This would be an unfunded cost additional to the unfunded cost already incurred for the opportunity cost of funds used to pay the initial tax liability. Incenta also note that their approach is consistent with the AER treatment of contributed assets used in provision of direct control services.[85]

98. HoustonKemp argue for the inclusion of contributed assets in the TAB to be depreciated over their useful life on the basis that this better reflects the actual tax liability.[86] HoustonKemp's description of the roll-forward model is accurate for a TAB in a post-tax model. However, they ignore the transition issue.

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85 Incenta, op cit, 29.

86 Houston Kemp, op cit, page 15

Overhead allocation

99. We understand that as part of its cost allocation model SAPN allocates shared overhead costs between its services.[87] ETSA Utilities' cost allocation method was approved by the AER in February 2009.[88] For direct control services, the overhead allocation forms part of the opex component of the PTRM and consequently the allowed revenue in the AER's determination.

100. We consider that as a general principle it is not desirable to adjust the overhead allocation to one service ex post. The allocation of these common costs to other services cannot now be altered.

87 ETSA Utilities, *Cost allocation method*, September 2008, page 17

88 AER, *ETSA Utilities cost allocation method: Final decision*, February 2009.

Elevation charge

101. The elevation charge has previously been described as analogous to the pole attachment charge levied on telecommunications carriers to attach their wires to stobie poles.

102. The SAIIR did not accept this analogy and argued that the level of the charge proposed by ETSA Utilities was not "fair and reasonable" on the basis that:[89]

(a) Public lighting is a public good and therefore the ETSA Utilities should not make a profit from it because there is no profit (to the council) that it should share (unlike a telecommunications provider which makes a profit from its services)

(b) Under the "regulatory bargain" ETSA Utilities can place assets on public land without charge; this detracts from the visual amenity of local premises. Under this regulatory bargain, ETSA Utilities should not charge for elevation where it does not incur an actual cost.

103. The SAIIR did however conclude that it "believes that there is justification for having an elevation charge."[90] It based this belief on recovering avoidable costs and as an "incentive payment for ETSA Utilities to continuously look for better asset utilisation".[91]

104. The ESCOSA view of the elevation charge was that:[92]

> *From a first principles perspective, the Commission agrees with ETSA Utilities that the price should lie between the avoidable and standalone cost of providing access to the pole. Any amount above ETSA Utilities' avoidable cost will provide it with an incentive to provide access and an amount below the standalone cost will provide an incentive for customers to use the existing assets rather than inefficiently duplicate the asset.*

105. ESCOSA also noted that the elevation charge was consistent with its decision in the Electricity Distribution Price Determination for 2005-2010 to introduce a profit-sharing or P-factor. The P-factor was intended to share profits derived by ETSA Utilities from providing unregulated services using regulated assets and where incremental costs were low, such as pole rental charges for the attachment of street lights and telecommunications equipment.[93]

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89 SAIIR, *Public Street Lighting Tariffs, Final Report*, November 2000, pages 35-36.

90 SAIIR, *Public Street Lighting Tariffs, Final Report*, November 2000, page 37.

91 Ibid.

92 ESCOSA, 2009, op. cit. page 31.

93 ESCOSA, *2005-2010 Electricity distribution price determination, Part A: Statement of reasons*, April 2005, page 12.

106. ESCOSA concluded that there "was an element of arbitrariness…and no economic rationale for apportioning the difference in avoidable and standalone costs between the beneficiaries."[94] It accepted that the existing charge was within the acceptable cost range and consistent with the 2000 charge and therefore was an appropriate element of a fair and reasonable public lighting tariff.

107. HoustonKemp argue that an elevation charge "does not reflect a cost incurred by SAPN for the provision of public lighting services and so its inclusion does not support the NEO."[95] This view is argued on the basis that only avoidable costs could be said to be "incurred" by SAPN and the avoidable cost of access to stobie poles is "close to zero".[96]

108. We agree with HoustonKemp that the NER principles relating to access to negotiated distribution services and the SAPN Negotiated Distribution Service Criteria are relevant. However, we do not agree that only avoidable costs are relevant. Both paragraph 6.7.1 (2) of the NER and Negotiated Distribution Service Criteria 6 provide that the price for public lighting should lie between the avoidable cost and the standalone cost of providing the service. Common costs are part of the standalone cost, but not part of the avoidable cost of providing a service, as by definition they are shared with the provision of another service. They are nonetheless incurred by SAPN.

109. There is, as ESCOSA noted, some arbitrariness to apportioning the difference between these two cost measures.[97] At a price less than the avoidable cost, SAPN would have no incentive to provide the service; at a price above the standalone cost the PLC would be better off establishing their own public lighting service.

110. It is not unusual for a rental to be charged for affixing something that relates to the provision of another service to an electricity distribution pole. This makes economic sense for both parties, in particular the party paying the rental wishes to avoid the cost of putting their own pole or other structure in place.

111. One of the arguments advanced appears to be that because SAPN owns the lights that are affixed to the poles, it should not include a pole rental in its cost structure. There is no economic argument that suggests that SAPN should treat a pole rental cost differently for itself compared to a third party: in substance this is a different expression of the avoidable cost versus standalone cost argument.

112. HoustonKemp also argue that to allow an elevation charge would be inconsistent with the promotion of the NEO.[98] Specifically, their report addresses two matters, that an elevation charge provides an incentive for SAPN to provide the public

94 ESCOSA, 2009, op cit. paragraph 168.

95 Houston Kemp Economists, *Expert report of Greg Houston: A report for HWL Ebsworth*, 6 February 2017, page 19.

96 Ibid, page 21.

97 Op cit, footnote 65.

98 HoustonKemp Economists, op cit, pages 22-23.

lighting service using its stobie poles and that it provides an incentive for a competitor to provide public lighting services.

113. With regard to the incentive to SAPN, consistent with the discussion of the avoidable cost and standalone cost, we agree that at prices greater than avoidable cost SAPN has an incentive to provide the service.

114. An elevation charge may provide an incentive for competitive entry if a competitor was able to access the stobie poles at the same elevation charge, but only if SAPN continued to charge themselves the same elevation charge.

115. A preferable approach, should the regulator be concerned that a DNSP is able to make super normal profit by virtue of being able to charge rentals for affixing things to the stobie poles would be to consider reducing the future revenue requirement for direct control services to reflect these other charges.

Appendix 1 NER Depreciation provision

6.5.5 Depreciation

(a) The depreciation for each regulatory year:

(1) must be calculated on the value of the assets as included in the regulatory asset base, as at the beginning of that regulatory year, for the relevant distribution system; and

(2) must be calculated:

(i) providing such depreciation schedules conform with the requirements set out in paragraph (b), using the depreciation schedules for each asset or category of assets that are nominated in the relevant Distribution Network Service Provider's building block proposal; or

(ii) to the extent the depreciation schedules nominated in the Distribution Network Service Provider's building block proposal do not so conform, using the depreciation schedules determined for that purpose by the AER.

(b) The depreciation schedules referred to in paragraph (a) must conform to the following requirements:

(1) the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets;

(2) 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 or category of assets 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;

(3) the economic life of the relevant assets and the depreciation methods and rates underpinning the calculation of depreciation for a given regulatory control period must be consistent with those determined for the same assets on a prospective basis in the distribution determination for that period.