Draft Decision

VENCorp

transmission determination

2008-09 to 2013-14

30 November 2007

AUSTRALIAN
ENERGY
REGULATOR

Request for submissions

This document sets out the Australian Energy Regulator's (AER) draft decision on VENCorp's electricity transmission determination for the period 1 July 2008 to 30 June 2014.

The AER will hold a predetermination conference on this draft decision on Wednesday 12 December 2007 for the purpose of explaining its draft decision and receiving oral submissions from interested parties. Interested parties can register to attend the pre-determination conference by contacting Maria Djopa on 03 9290 1436 or at aerinquiry@aer.gov.au, by Friday 7 December 2007.

Issues regarding this draft decision can be addressed in written submissions to the AER by 19 February 2008.

Submissions can be sent electronically to aerinquiry@aer.gov.au.

Alternatively, submissions can be sent to:

> Mr Chris Pattas
> General Manager
> Network Regulation South
> Australian Energy Regulator
> GPO Box 520
> Melbourne VIC 3000

The AER prefers that all submissions be publicly available to facilitate an informed and transparent consultative process. Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information are requested to:

- clearly identify the information that is the subject of the confidentiality claim, and
- provide a non-confidential version of the submission.

All non-confidential submissions will be placed on the AER's website at www.aer.gov.au.

Copies of VENCorp's revenue proposal, proposed negotiating framework and proposed pricing methodology, and of the reports of the AER's consultants and interested parties, are available on the AER's website.

Enquiries about the draft decision, or about lodging submissions, should be directed to the AER's Network Regulation South branch on (03) 9290 1437.

Contents

Overview

Under the National Electricity Law (NEL) and the National Electricity Rules (NER), the Australian Energy Regulator (AER) is responsible for the economic regulation of monopoly transmission services in the National Electricity Market (NEM).

VENCorp submitted its revenue proposal and proposed negotiating framework for the 1 July 2008 to 30 June 2014 regulatory period on 1 March 2007. VENCorp's pricing methodology was submitted separately on 7 June 2007.

After it published its 2007 Electricity Annual Planning Report (2007 EAPR) in June 2007, VENCorp submitted a reconciliation of its revenue proposal and the 2007 EAPR to the AER. The reconciliation presented revised forecasts of planned augmentation expenditure and planned augmentation charges, and a recalculation of VENCorp's proposed maximum allowable aggregate revenue (MAAR). This draft decision has taken these revisions to VENCorp's proposal into account.

The transmission arrangements in Victoria, which separate the network asset owner (predominately SP AusNet) from the investment decision-maker (VENCorp) are unique in the NEM. SP AusNet owns and operates the transmission network and provides bulk transmission services to VENCorp under a network services agreement. VENCorp owns no transmission assets itself, but provides shared network services to users and is responsible for planning and directing the augmentation of the shared network (which excludes the connection facilities utilised by generators and distribution bodies).

The AER makes determinations according to the NER in respect of certain services made by transmission businesses, including VENCorp. The requirements for VENCorp's transmission determination are found in the NER, in both Chapter 6A, which applies to all transmission businesses, and the jurisdictional derogation for Victoria in Chapter 9, Part A. The derogation is designed to accommodate the unique Victorian transmission model. This means the application of Chapter 6A in respect of the Victorian Transmission Network or a part of the Victorian Transmission Network is subject to some modifications. Chapter 6A is not displaced, and continues to apply to VENCorp, as modified by the derogations in Chapter 9.

VENCorp's role is different to that of other TNSPs. The determination of its revenue, and in particular the components of VENCorp's revenue determination, therefore differs in a number of respects to the determination of revenue for other TNSPs. VENCorp's MAAR is the total of forecasts of its operating expenditure, planned augmentation charges, committed augmentation charges and prescribed service charges payable to SP AusNet and Murraylink for the provision of prescribed services by those TNSPs, adjusted for any surplus or deficit accumulated in the current regulatory period.

The AER proposes to allow revenues for VENCorp that increase from $373.08m (nominal) in 2008-09 to $516.85m (nominal) in 2013-14. On average, this allowed revenue is around 6% less than that proposed by VENCorp, which would have resulted in a MAAR of $405.00m (nominal) in 2008-09, increasing to $565.70m (nominal) in 2013-14. While lower than those proposed by VENCorp, the revenues allowed under the draft decision provide a more accurate, cost-reflective indication of the efficient transmission price path for the forthcoming regulatory period, which will assist in planning investment in the forthcoming regulatory period. The review process provides independent and objective scrutiny of each building block in the revenue allowance that VENCorp seeks, and in doing so imposes some cost discipline on VENCorp as a monopoly service provider, and enhances transparency for users. The AER is confident that the allowed revenue will enable VENCorp to manage cost pressures and continue to meet system constraints emerging towards the end of the forthcoming control period.

The main areas of difference between VENCorp's proposal and the AER's draft decision are adjustments for evident overstatement of VENCorp's revenue requirements for the forthcoming regulatory period:

- **Operating expenditure (opex)** – VENCorp proposed a total opex forecast of $44.00m (nominal) over the regulatory period. The AER has reduced this by $4.63m (11%) and approved a lower opex forecast of $39.37m (nominal).
- **Committed augmentation charges** – The AER has removed $22.84m (nominal), or 15%, from VENCorp's forecast of committed augmentation charges for the forthcoming period due to several calculation errors in VENCorp's supporting material. These errors have been confirmed by VENCorp.
- **Planned augmentation expenditure and charges** – The AER has reduced the forecast of planned augmentation charges in VENCorp's revised proposal from $63.21m (nominal) to $46.18m (nominal), a reduction of $17.03m (27%). This reduction corrects the overtly conservative forecast of planned augmentation expenditure from which VENCorp's forecast charges were calculated. The AER has based the approved forecast charges on a more realistic expenditure forecast of $200.78m ($2007-08), a reduction of $152.2m from VENCorp's initial proposal, or $87.39m (30%) following VENCorp's adjustments for the 2007 EAPR. The AER is satisfied that this lower allowance will allow VENCorp to meet its statutory objectives in the forthcoming regulatory period.
- **Prescribed service charges** – The AER has reduced VENCorp's forecast of prescribed service charges by $70.09m (nominal) to take into account the AER's draft decision on SP AusNet's transmission determination, which was released on 31 August 2007. The AER has also adjusted VENCorp's forecast of prescribed service charges for Murraylink, which was based on a revenue cap that was revoked in 2004. The revised forecast properly reflects Murraylink's current revenue cap in 2004.
- **Accumulated surplus** – The AER has made an adjustment to VENCorp's MAAR for the first year of the regulatory period to remove the $25.19m (nominal) surplus VENCorp is expected to have accumulated at the end of the current regulatory period.

The resultant adjustment to VENCorp's proposed MAAR is a reduction of $175.87m (nominal), or 6%, over the forthcoming regulatory period.

As submitted to the AER, VENCorp's proposal would have resulted in an average annual nominal price increase of 7% (4% real), equating to an expected per MWh price that will gradually increase from $7.74 (nominal) in 2008-09 to $10.60 (nominal) in 2013-14.

By contrast, the transmission price impact of the MAAR for VENCorp set out in this draft decision would be a nominal per MWh "price" of $7.13 in 2008-09, increasing by an average of 6% per year to $9.68 in 2013-14.

Summary

Introduction

The ACCC determined VENCorp's current revenue cap for the five and a half year period from 1 January 2003 to 30 June 2008 in accordance with its responsibilities under the National Electricity Code (NEC). The AER assumed responsibility for regulating electricity transmission services provided by VENCorp on 1 July 2005. VENCorp's proposal and this draft decision have been made in accordance with the jurisdictional derogation for Victoria in chapter 9, part A of the NER (the derogation), and the new chapter 6A, which took effect on 16 November 2006.

The process and timing for the making of VENCorp's transmission determination are considerably modified under the derogation, which provides for an abbreviated, single-stage process for all aspects of VENCorp's transmission determination, with the exception of its pricing methodology. In the interests of consistency with the process to be followed by SP AusNet, and to facilitate the input of interested parties, the AER requested, and VENCorp agreed, to submit its proposal at the same time as SP AusNet, thus enabling the AER to publish and consult on both applications over a similar time-frame.

The key stages of the process leading to the release of this draft decision are:

- VENCorp's initial revenue proposal and its proposed negotiating framework were submitted to the AER on 1 March 2007, and resubmitted on 1 May 2007 following the AER's preliminary examination and determination of non-compliance under cl. 6A.11.1. For the purposes of this draft decision, the 1 May 2007 proposal is referred to as the "initial proposal".
- VENCorp's initial proposal was published by the AER on 1 May 2007, and interested parties were invited to make submissions. A public forum was held in Melbourne on 10 May 2007, at which VENCorp gave a presentation to interested parties on its proposal.
- Further consultation was undertaken on VENCorp's proposed pricing methodology, which was submitted on 7 June 2007, and on the AER's proposed negotiated transmission services criteria for VENCorp.
- On 19 July 2007, at the request of the AER, VENCorp provided a reconciliation of its initial proposal and the 2007 EAPR published by VENCorp on 21 June 2007. The reconciliation document, which is available on the AER's website, presents a revised forecast of planned augmentation expenditure derived from the 2007 EAPR, revised forecasts of planned augmentation charges and prescribed service charges, and a revised proposed MAAR. The other components of VENCorp's initial proposal remain untouched by the reconciliation. For the purposes of this draft decision, the initial proposal as amended by the reconciliation is referred to as the "revised proposal".

The opportunity to update or revise a revenue proposal after it has been submitted and consultation has commenced is not contemplated in either the derogation or chapter 6A. The AER was able to give VENCorp this opportunity under the agreed, extended process settled prior to commencement of this review.

The AER engaged technical consultants to provide independent, objective advice on VENCorp's revenue proposal:

- PB Strategic Consulting (PB) was engaged by the AER to provide independent engineering advice on VENCorp's committed augmentation expenditure, and the forecasts of planned augmentation expenditure, planned augmentation charges and operating expenditure in VENCorp's initial proposal.
- Nuttall Consulting was engaged to provide additional expert engineering advice on VENCorp's proposal, and the impact of VENCorp's reconciliation of its initial proposal and the 2007 EAPR on PB's recommendations on the initial proposal.

The consultants' reports have been published with this draft decision.

The key components of this draft decision are:

- The AER's draft determination of VENCorp's MAAR, including:
  - an assessment of VENCorp's forecast operating expenditure
  - an assessment of VENCorp's forecast committed augmentation charges
  - an assessment of VENCorp's forecast of planned augmentation charges and the forecast of planned augmentation expenditure on which it is based
  - a determination of VENCorp's maximum allowable aggregate revenue (MAAR) for each financial year of the forthcoming regulatory period
- The AER's draft determination in relation to VENCorp's proposed negotiating framework
- The AER's draft determination of the negotiated transmission service criteria that will apply to VENCorp
- The AER's draft determination in relation to VENCorp's proposed pricing methodology.

The AER's consideration of each of these components is summarised below. Further detail is provided in the relevant chapters, and in the detailed appendices to this draft decision.

Operating Expenditure

VENCorp is responsible for the planning, development and augmentation of the Victorian electricity transmission network, and for the provision of common services or network services that are transmission services.[1] The forecast of operating expenditure (opex) that VENCorp is required to include in its proposal relate to:

[1] NER cl. 9.3.2(a)(1)(i)

- VENCorp's aggregate forecast operating costs in planning the Victorian transmission network and
- any other opex related costs that directly arise out of VENCorp's functions under the *Electricity Industry Act 2000* (Vic) relating to the transmission of electricity, the application of the National Electricity Rules (NER) to VENCorp or the conditions imposed on VENCorp under its transmission licence relating to the transmission of electricity, for which there is no alternative method (legislative or contractual) for the recovery of those costs.[2]

Unlike other TNSPs, VENCorp does not own transmission assets, nor does it undertake maintenance of a transmission network. Accordingly, VENCorp's forecast operating expenditure (opex) does not relate to routine maintenance or other analogous costs that would be included in the opex forecasts of other TNSPs. VENCorp's forecast opex is only comprised of corporate related costs.

VENCorp's forecast must set out the operating expenditure required to achieve the following objectives:

- meet the expected demand for prescribed transmission services over the regulatory period
- comply with all applicable regulatory obligations associated with the provision of prescribed transmission services
- maintain the quality, reliability and security of supply of prescribed transmission services, and
- maintain the reliability, safety and security of the transmission system through the provision of prescribed transmission services.

Before it can approve VENCorp's forecast of operating expenditure, the AER must be satisfied that it reasonably reflects:

- the efficient costs of meeting the above objectives
- the costs that a prudent operator in VENCorp's circumstances would require to meet those objectives, and
- a realistic expectation of the demand forecast for the relevant regulatory period, and of the cost inputs required to meet those objectives.

AER's considerations

Clause 9.8.4C(a) of the derogation requires that VENCorp's MAAR must be set on a full cost recovery, no operating surplus basis, so as not to exceed VENCorp's statutory electricity transmission related costs. The AER's assessment of the forecast opex that VENCorp proposes be included in its MAAR under cl. 6A.6.6 of the NER has been made in that context, and recognises the difference between the costs VENCorp seeks to recover through its forecast opex allowance and those generally included in a TNSP's opex forecast.

VENCorp proposed a total opex forecast of $44m (nominal) for the forthcoming regulatory period. The AER is not satisfied that VENCorp's proposed forecast of

[2] NER cl. 9.3.1(2)

$44m (nominal) reasonably reflects the opex criteria; and accordingly has not accepted the forecast opex in VENCorp's revenue proposal.

The AER has substituted an opex forecast of $39.37m (nominal) which the AER is satisfied reasonably reflects the opex criteria, taking into account the relevant opex factors. In making this adjustment the AER has:

- accepted VENCorp's proposed base year of 2006-07, from which to forecast its future opex requirements. However the AER has substituted VENCorp's budgeted 2006-07 expenditure with its actual 2006-07 expenditure, which was available subsequent to the preparation of VENCorp's initial application to the AER in March 2007. The AER has also made a positive adjustment to the actual 2006-07 expenditure to remove the effect of the defined benefit superannuation adjustment, which the AER considers is not relevant to VENCorp's future opex requirements, and
- accepted VENCorp's proposed cost escalators of 4.5% (nominal) for labour and 3.0% (nominal) for non-labour costs.

The AER is satisfied that VENCorp's cost allocation methodology allocates only statutory electricity transmission-related costs to VENCorp's electricity segment cost accounts. As these accounts have been used to project VENCorp's opex allowance the AER is satisfied the opex component of VENCorp's MAAR will not exceed VENCorp's statutory transmission-related opex costs. The AER is also satisfied that the opex allowance determined by the AER will result in the opex component of VENCorp's MAAR being set on a full cost recovery but no operating surplus basis.

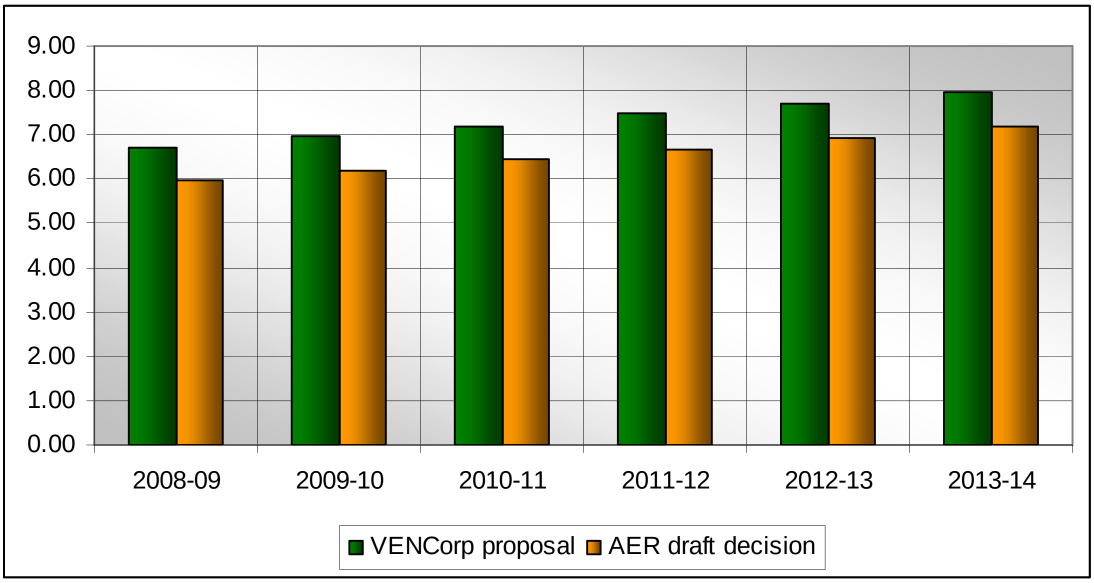
Table 1 AER's draft decision – Opex ($m, nominal)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
VENCorp's proposal	6.69	6.98	7.17	7.47	7.71	7.98	44.00
AER's adjustment	-0.70	-0.78	-0.74	-0.80	-0.80	-0.81	-4.63
AER's draft decision	5.99	6.20	6.43	6.67	6.91	7.17	39.37

Source: VENCorp[3], AER analysis

[3] VENCorp, *VENCorp Electricity Revenue Cap Proposal – 1 July 2008 to 30 June 2014*, p. 35.

Figure 1 AER's draft decision – Opex ($m, nominal)



Source: VENCorp[4], AER analysis

Committed augmentation charges

VENCorp is responsible for the planning, development and augmentation of the Victorian electricity transmission network.[5] Unlike other TNSPs, VENCorp does not own any transmission assets, and does not have a RAB. It fulfils its statutory responsibilities to augment the network by procuring bulk transmission services under contract from SP AusNet and other owners of Victorian electricity transmission assets.

Network augmentation expenditure is incurred by VENCorp in the form of charges payable by VENCorp to transmission asset owners for the provision of bulk transmission services provided under contracts won through a contestable tender process, or where otherwise directed by VENCorp in the current regulatory period. In VENCorp's revenue proposal and this draft decision these charges are referred to as committed augmentation charges if the contract has already been entered into. The total expenditure underlying these charges, which will be recovered over the life of the contract, is referred to as committed augmentation expenditure. In each regulatory period, it is the committed augmentation charges payable in that period, and not the total value of the relevant contracts, that form one of the building blocks of VENCorp's MAAR.

Under cl. 9.8.4C(a) of the Victorian jurisdictional derogation, VENCorp's MAAR must be set to allow VENCorp to fully recover its statutory electricity transmission related costs, including charges payable under contracts entered into in the current regulatory period, and existing contracts from before that period.

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[4] ibid.
[5] NER cl. 9.3.2(a)(1)(i)(A). SP AusNet as owner is responsible for asset replacement.

The effect of this derogation is to permit VENCorp to recover, as part of its MAAR, the actual charges that will be paid under existing contracts that have already been made. Accordingly, the capital expenditure criteria set out in cl 6A.6.7(c) do not apply in their entirety to this part of VENCorp's revenue proposal. There is no scope for the AER to review the prudency or efficiency of committed augmentation expenditure, since VENCorp is entitled to recover all charges that will be paid under existing contracts. This means that cl. 6A.6.7(c)(1) and (2) have no application to this part of VENCorp's revenue proposal. The AER has therefore not conducted an ex-post prudency assessment of VENCorp's augmentation expenditure in the current regulatory period, as it has done for SP AusNet.

However, cl. 6A.6.7(c)(3) is applicable, to the extent that the AER must be satisfied that VENCorp's forecast of its committed augmentation expenditure reasonably reflects a realistic expectation of the charges that it will incur under its existing contracts in the coming regulatory period. This is ensure that the MAAR, which is set on the basis of that forecast, will not exceed VENCorp's statutory electricity transmission related costs and is set on a full cost recovery but no operating surplus basis, as required by the derogation.

VENCorp's revenue proposal describes the augmentation projects that the ACCC approved when setting VENCorp's revenue cap in 2002 and the augmentation projects to which VENCorp has already committed itself during the current period. However, VENCorp has only set out the value of each of these projects (ie. the estimated value of each of these contracts over the contract life). VENCorp has not set out the forecast charges payable under these contracts over the coming regulatory period.

VENCorp has explained that its forecast of committed augmentation charges is instead derived from its budgeted network payments for 2008-09, the first year of the forthcoming regulatory period. For the remaining years of the forthcoming regulatory period, VENCorp states that it has inflated its 2008-09 forecast by an assumed CPI of 3% per annum.[6]

Table 2 VENCorp proposal — Committed augmentation charges for the forthcoming period ($m, nominal excluding GST).

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
Committed augmentation charges	22.9	23.6	24.3	25.0	25.7	26.5	148.0

Source: VENCorp[7]

AER's considerations

In the course of reviewing and verifying the calculations in the underlying spreadsheet provided by VENCorp, the AER identified, and VENCorp confirmed, a number of errors in the form of inappropriate inclusion and exclusion of contracts in VENCorp's

[6] Email VENCorp to AER, 17 October 2007
[7] VENCorp, *op cit*, p. 25

calculations. The correct calculation of network payments in VENCorp's forecast for 2008-09 should in fact be $19.35m (nominal), and not $22.90m (nominal) as indicated in its revenue proposal.

The AER does not consider that VENCorp's justification of a 3% inflation escalator is appropriate. It ignores the downward trend in the real price of the contract charges over the life of a contract that results from the application of the WACC to a depreciating asset base, which forms a major component of the overall charges payable by VENCorp. However, when considered in the context of the uncertainty surrounding potential contract variations within the regulatory period, and the inflation adjustments to the contract charges within the period, it is not unreasonable to expect that, within the forthcoming regulatory period, committed augmentation charges will in fact increase over time. While not endorsing VENCorp's argument that charges should be inflated by CPI, the AER considers on the balance of the information provided that an assumed increase of 3% per annum is not unrealistic.

When applied to the corrected forecast of $19.35m (nominal), this 3% per annum increase produces a forecast of committed augmentation charges for the forthcoming regulatory period that is $22.84m (nominal) lower than that in VENCorp's revenue proposal. In light of the identified errors leading to this overstatement, the AER is not satisfied, with regard to the criterion set out on cl. 6A.6.7(c)(3) and the information included in and accompanying VENCorp's revenue proposal, that VENCorp's forecast of committed augmentation charges reasonably reflects a realistic expectation of the charges that it will incur under its existing contracts in the forthcoming regulatory period.

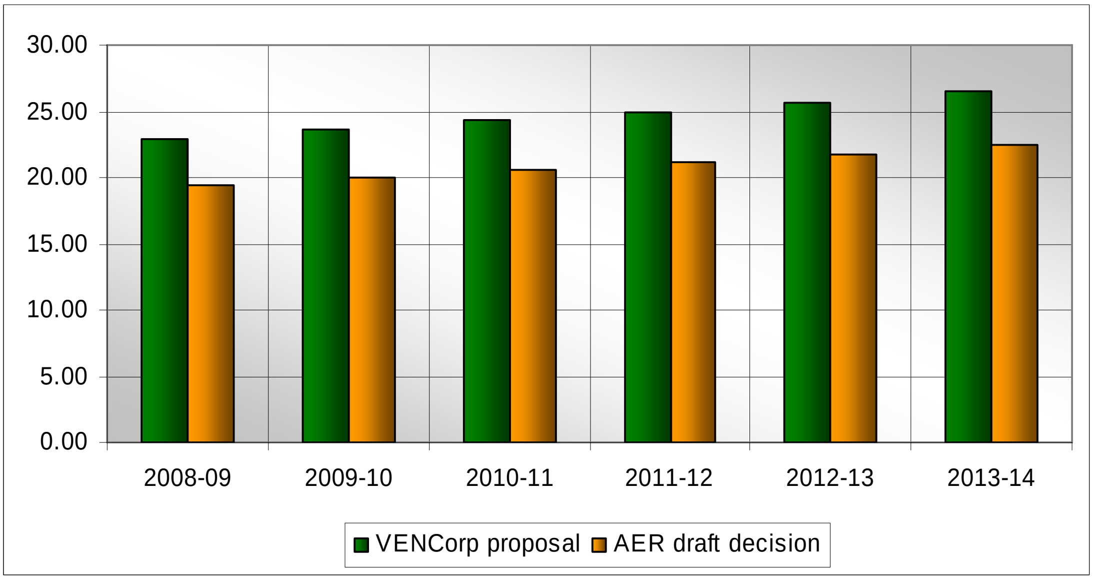
For the purposes of this draft decision, the AER has substituted its own forecast of committed augmentation charges, which has been derived from the corrected estimate of charges payable in 2008-09, escalated by 3% per annum in each subsequent year of the regulatory period.

Table 3: AER's draft decision – Committed augmentation charges ($m, nominal)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
VENCorp's proposal	22.9	23.6	24.3	25.0	25.7	26.5	148.00
AER's adjustment	-3.55	-3.67	-3.77	-3.86	-3.92	-4.07	-22.84
AER's draft decision	19.35	19.93	20.53	21.14	21.78	22.43	125.16

Source: VENCorp, AER analysis

Figure 2: AER draft decision – Committed augmentation charges ($m, nominal)



Source: AER analysis

Planned augmentation expenditure and charges

VENCorp plans and procures augmentation services under contract from SP AusNet and other owners of Victorian electricity transmission assets.

Where other TNSPs forecast capex, VENCorp derives a forecast of the contract charges that will be payable in the relevant regulatory period in respect of new contracts entered into for planned augmentations, on the basis of an indicative planned augmentation expenditure forecast. In VENCorp's proposal and this draft decision, this is referred to as VENCorp's forecast planned augmentation *expenditure*. The forecast contract charges expected to flow from this expenditure are referred to as VENCorp's forecast planned augmentation *charges*. It is forecast planned augmentation charges, rather than the forecast planned augmentation expenditure underlying it, that form the building block in VENCorp's MAAR.

The AER's review of VENCorp's forecast planned augmentation charges involves a review of:

- the forecast planned augmentation expenditure from which they have been calculated
- the methodology applied in calculating forecast charges on the basis of the forecast of expenditure and
- the forecast planned augmentation charges.

In assessing VENCorp's forecast planned network augmentation expenditure, the AER has applied the provisions of cl. 6A.6.7 of the NER. This clause sets out the requirements for the proposal and assessment of forecast capital expenditure, including augmentation expenditure, to VENCorp's forecast planned network augmentation expenditure and forecast planned augmentation charges.

VENCorp's forecast must set out the planned augmentation expenditure required to achieve the following objectives:

- meet the expected demand for prescribed transmission services over the regulatory period
- comply with all applicable regulatory obligations associated with the provision of prescribed transmission services
- maintain the quality, reliability and security of supply of prescribed transmission services, and
- maintain the reliability, safety and security of the transmission system through the provision of prescribed transmission services.

Before it can approve VENCorp's forecast planned augmentation expenditure, the AER must be satisfied that it reasonably reflects:

- the efficient costs of meeting the above objectives
- the costs that a prudent operator in VENCorp's circumstances would require to meet those objectives, and
- a realistic expectation of the demand forecast for the relevant regulatory period, and of the cost inputs required to meet those objectives.

The application of chapter 6A to VENCorp is modified by the chapter 9 derogation. Clause 9.8.4C(a) requires that VENCorp's MAAR must be set on a full cost recovery, no operating surplus basis, so as not to exceed VENCorp's statutory electricity transmission related costs. The AER's assessment of the forecast planned augmentation charges that VENCorp proposes be included in its MAAR under cl. 6A.6.7 of the NER has been made in that context, and recognises the difference between the costs VENCorp seeks to recover through its forecast planned augmentation charges allowance and those generally included in a TNSP's capex forecast.

VENCorp's initial revenue proposal forecast $353.90m ($2007-08) of expenditure on network augmentation over the forthcoming period.[8] This represents an increase of approximately 150% from the actual expenditure in the current period. VENCorp explains that the increase in the augmentation expenditure for the forthcoming period is driven by the increase from a five to six year regulatory period,[9] and the increasing cost of network assets around the globe.[10] In developing its forecast planned augmentation expenditure, VENCorp has employed an indicative probabilistic planning methodology that is consistent with that used to develop the ten-year outlook contained in VENCorp's EAPR.

VENCorp's initial revenue proposal was based largely on its 2006 EAPR. The reconciliation of the initial revenue proposal with the 2007 EAPR significantly revised the forecast planned augmentation expenditure[11], and the forecast planned augmentation charges.

[8] VENCorp, *op cit*, p. 33
[9] The duration of VENCorp's current regulatory period is actually five and a half years.
[10] VENCorp, *op cit*, p. 30
[11] VENCorp's forecast of planned augmentation expenditure fell from $354m to $288m, largely as a result of its withdrawal of the claim for a +25% contingency on all elements of its forecast.

Table 4: VENCorp revised proposal — Forecast planned augmentation expenditure ($m, 2007–08)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Total
VENCorp initial proposal	2.0	15.6	51.7	79.3	138.0	67.3	**353.9**
VENCorp revised proposal	2.6	9.3	43.3	74.8	75.8	82.2	**288.2**
Difference	0.6	-6.3	-8.4	-4.5	-62.2	14.9	**-65.7**

Source: VENCorp[12], AER analysis

AER's considerations

Planned augmentation expenditure

The AER is not satisfied that VENCorp's revised forecast planned augmentation expenditure of $288.18m ($2007-08) reasonably reflects the criteria established in the NER. The AER has made a downward adjustment of $87.39m to produce a substitute forecast of $200.78m ($2007-08), which it considers necessary for it to be satisfied that VENCorp's proposed allowance reasonably reflects these criteria. This represents a reduction of 30%.

The largest reduction ($50.75m, $2007-08) is the result of the detailed project reviews conducted by PB for the AER. The AER also made a further reduction of $24.42m ($2007-08) to other general allowances in VENCorp's forecast program on the basis of PB's findings. The key driver for these reductions was VENCorp's inability to satisfy the AER that there was a justified need for the expenditure in the forthcoming regulatory period, such that VENCorp was likely to incur the associated expenditure. In some respects, the approach taken by VENCorp in preparing its forecast of planned augmentation expenditure lacked the degree of rigour typically applied in the development of a revenue proposal.

The AER also examined the basis for the costs included in VENCorp's proposal and made an additional downward adjustment of $12.21m ($2007-08) to reflect an appropriate cost escalation. This adjustment was based on the AER's earlier decisions on cost escalators for SP AusNet, which relate to cost inputs comparable to those informing VENCorp's proposed forecast planned augmentation expenditure.

These adjustments are set out in table 5 below.

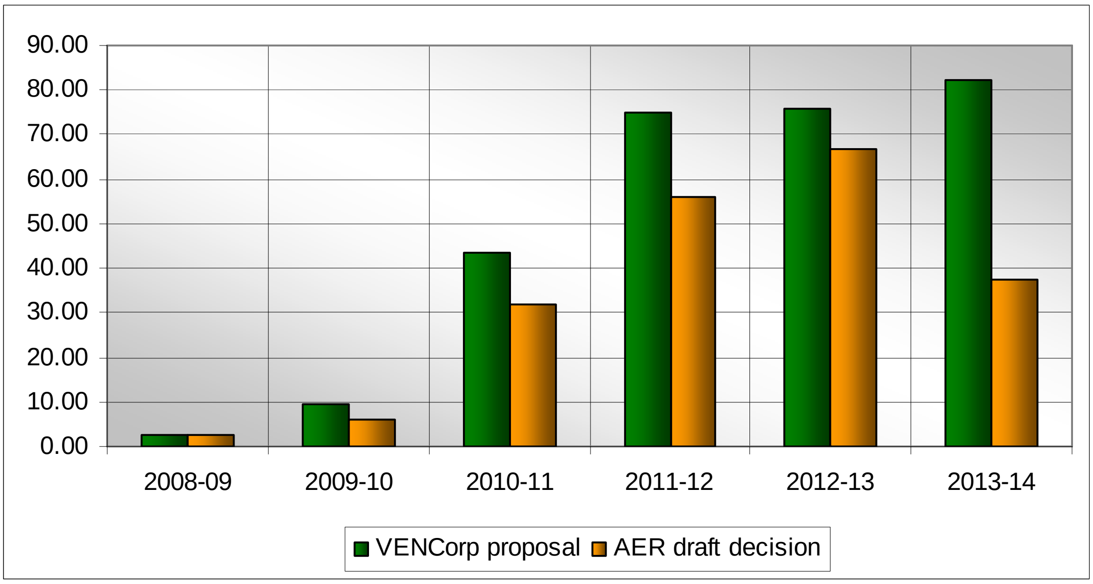
[12] VENCorp, VENDOCS #194410, #215183

Table 5: AER's draft decision — Forecast planned augmentation expenditure ($m, 2007-08)

	2008–09	2009–10	2010–11	2011-12	2012-13	2013-14	Total
VENCorp revised proposal	2.60	9.30	43.34	74.84	75.84	82.24	288.16
AER adjustment	–	-3.25	-11.54	-18.73	-9.04	-44.81	-87.38
AER's draft decision	2.60	6.05	31.80	56.11	66.80	37.43	200.78

Source: VENCorp, AER analysis

Figure 3 AER draft decision – Forecast planned augmentation expenditure ($m, 2007-08)



Source: VENCorp[13], AER analysis

Planned augmentation charges

Having determined that the forecast planned augmentation expenditure on which VENCorp's forecast planned augmentation charges are based does not satisfy the requirements of the NER, the AER is not satisfied that the forecast charges reasonably reflect a realistic expectation of the charges that VENCorp will incur in the forthcoming regulatory period. The inclusion of VENCorp's forecast charges in its MAAR would be inconsistent with the principles in cl. 9.8.4C(a) of the NER: the amount of VENCorp's MAAR must not exceed VENCorp's expected statutory electricity transmission related costs, and must be determined on a full cost recovery, but no operating surplus basis.

The AER has reviewed the methodology VENCorp has applied to convert its forecast planned augmentation expenditure into planned augmentation charges and is satisfied that it is an appropriate methodology for converting expenditure amounts to charges,

[13] Letter VENCorp to AER, 19 July 2007.

resulting in an outcome that is reasonably reflective of the costs that VENCorp will incur.

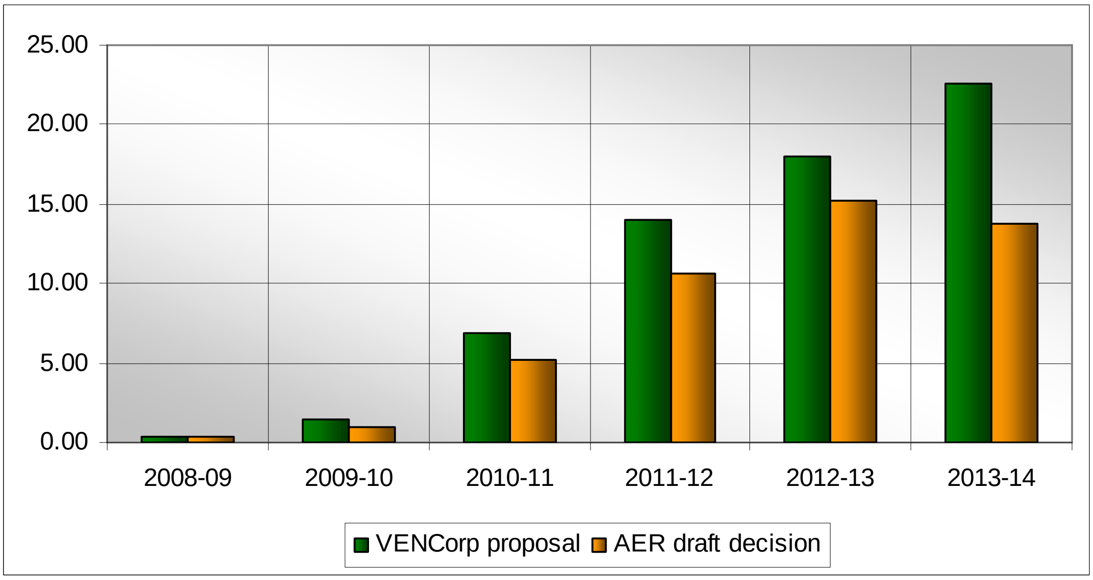
The AER has applied this methodology to the revised forecast of planned augmentation expenditure in table 5 above to calculate the revised forecast of planned augmentation charges shown below. In doing so, the AER has substituted the WACC of 8.5% applied in VENCorp's proposal with the indicative WACC of 8.85% applied in the AER's draft decision on SP AusNet.

Table 6: AER draft decision — Forecast planned augmentation charges ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Total
VENCorp's revised proposal	0.36	1.45	6.89	14.00	17.98	22.53	63.21
AER's adjustment	0.01	-0.44	-1.73	-3.33	-2.73	-8.81	-17.03
AER's draft decision	0.37	1.01	5.16	10.67	15.25	13.72	46.18

Source: VENCorp, AER analysis

Figure 4: AER draft decision — Forecast planned augmentation charges ($m, nominal)



Source: AER analysis

Maximum allowable aggregate revenue

Pursuant to cl. 9.8.4C, in determining VENCorp's MAAR for each financial year of the forthcoming regulatory period the AER must have regard to the following principles:

- the amount of VENCorp's MAAR must not exceed VENCorp's statutory electricity transmission-related costs, and

- VENCorp's MAAR must be determined on a full cost recovery but no operating surplus basis.

- must take into account VENCorp's functions under the *Electricity Industry Act 2000* (Vic) relating to the transmission of electricity, the application of the NER to VENCorp and the conditions imposed on VENCorp under its transmission licence, and
- must take into account the difference between the revenue that VENCorp will recover by way of shared transmission network use charges and its statutory electricity transmission-related costs over the current regulatory period (i.e. VENCorp's accumulated surplus/deficit at the end of the current regulatory period).

On 17 July 2007, VENCorp revised the forecasts for several components of its MAAR, from the initial proposal submitted (and published) on 1 May 2007. In its revised proposal, VENCorp proposes a total MAAR of $2 889.80m (nominal) for its forthcoming regulatory period.[14] The revisions from VENCorp's initial proposal consist of:

- revisions to VENCorp's planned augmentation charges to reconcile the charges with the planned augmentation expenditure outlined in its 2007 EAPR, released on 21 June 2007 – after the submission of its initial proposal, and
- revisions to VENCorp's prescribed services charges to reflect a change in the recognition of the availability incentive scheme (AIS). VENCorp states that, having had the opportunity to consider SP AusNet's revenue proposal, VENCorp has now removed the allowance sought for rebates under the AIS in its initial proposal, given that SP AusNet has sought a rebate allowance in its revenue proposal.[15]

For the purposes of assessing VENCorp's proposal under the NER, the AER accepts VENCorp's proposal as incorporating the revisions listed above and submitted to the AER on 17 July 2007. VENCorp's revised proposal is outlined in the table below.

[14] VENCorp, Letter to AER – Reconciliation of VENCorp Electricity Transmission Network Revenue Proposal for the Period 1 July 2008 to 30 June 2014 with the 2007 Electricity Annual Planning Report, 19 July 2007, p. 6.
[15] ibid.

Table 7: VENCorp's proposal – MAAR ($m, nominal)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
Operating expenditure	6.69	6.98	7.17	7.47	7.71	7.98	**44.00**
Committed augmentation charges	22.90	23.60	24.30	25.00	25.70	26.50	**148.00**
Planned augmentation charges	0.36	1.45	6.89	14.00	17.98	22.53	**63.21**
Total VENCorp expenditure	**30.00**	**32.00**	**38.40**	**46.50**	**51.40**	**57.00**	**255.20**
Prescribed services charges*	370.00	393.50	418.60	445.20	473.50	503.70	**2 604.50**
MAAR**	**405.00**	**430.50**	**462.00**	**496.70**	**529.90**	**565.70**	**2 889.80**
Energy (Mwh)	52.35	51.67	51.67	51.81	52.78	53.38	
TUOS charges ($/Mwh)	**7.74**	**8.33**	**8.94**	**9.59**	**10.04**	**10.60**	

Source: VENCorp[16]
* For SP AusNet, Murraylink
** VENCorp's revised proposal has removed the annual $6m allowance for the AIS from its forecast prescribed service charges, but its MAAR erroneously includes the allowance. The MAAR calculation in this table also includes an annual reduction of $1m to account for interest income that VENCorp expects to earn during the regulatory period.

Details of the AER's draft decision on VENCorp's proposed forecasts of operating expenditure, committed augmentation charges and planned augmentation have been discussed separately above.

Prescribed services charges

VENCorp's revised proposal includes total forecast prescribed services charges of $2 604.50m (nominal). These charges relate to payments made by VENCorp to SP AusNet and Murraylink for the provision of prescribed transmission services. The AER notes that certain assumptions must be made to derive a forecast of prescribed services charges – the AER's assessment of the assumptions made by VENCorp follows.

SP AusNet's prescribed services charges

- Prescribed services charges payable to SP AusNet comprise the majority of VENCorp's prescribed services charges forecast. VENCorp's forecast was based on SP AusNet's original revenue proposal. The AER has updated this aspect of VENCorp's proposal to reflect the AER's draft decision on SP AusNet's proposal, and notes that these charges will need to be updated again after the release of the

[16] ibid.

AER's final decision on SP AusNet, should the final decision differ from the draft decision.

- The AER has corrected for the difference in regulatory years between SP AusNet and VENCorp.[17]
- The AER accepts VENCorp's assumptions that approximately 85% of SP AusNet's (non-easement tax) MAR and 100% of SP AusNet's easement tax is recovered through VENCorp.

Murraylink prescribed services charges

- VENCorp's prescribed services charges forecast appears to have been based on the ACCC's 2003 Murraylink decision.[18] However, this decision was revoked and substituted in 2004.[19] Accordingly the AER has forecast the Murraylink prescribed services charges from the substituted decision.
- As VENCorp's forthcoming regulatory period extends one year beyond Murraylink's current regulatory period the AER was required to make an assumption about Murraylink's MAR for the first year beyond its current regulatory period, and has adopted the x factor and forecast inflation rate in the Murraylink decision to make this extrapolation.
- The AER accepts VENCorp's assumption that 55% of Murraylink's MAR is recovered through VENCorp.

Based on the above assumptions the AER has made an adjustment of $70.09m (nominal) to VENCorp's total prescribed services forecast. However as previously noted, this adjustment will need to be updated to reflect differences (if any) between the SP AusNet draft and final decisions.

Table 8: AER's draft decision – prescribed services charges ($m, nominal)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
VENCorp's proposal	370.00	393.50	418.60	445.20	473.50	503.70	2 604.50
AER's adjustment	+3.57	-1.34	-7.74	-13.85	-21.56	-29.17	-70.09
AER's draft decision	**373.57**	**392.16**	**410.86**	**431.35**	**451.94**	**474.53**	**2 534.41**

Source: VENCorp, AER analysis

[17] Email VENCorp to AER, 21 September 2007. SP AusNet's regulatory control period commences on 1 April 2008 to coincide with the start of the Singapore financial year. VENCorp's regulatory period commences on 1 July 2008.

[18] ACCC, *Decision – Murraylink Transmission Company Application for Conversion and Maximum Allowed Revenue*, 1 October 2003.

[19] ACCC, *Revocation and substitution of revenue cap*, letter to Murraylink Transmission Company, 1 April 2004.

Other adjustments

Interest income

In its proposal, VENCorp reduced the sum of its forecast opex, committed augmentation charges, planned augmentation charges and prescribed services charges by $1m (nominal), in each year, to account for the interest income VENCorp expects to earn annually during its forthcoming regulatory period.[20]

The AER considers the reduction of forecast interest income from VENCorp's forecast statutory electricity transmission-related costs is important to ensure that VENCorp's MAAR is determined on a full cost recovery and no operating surplus basis. The AER accepts VENCorp's forecast of interest income as reasonable, though notes that based on recent experience, it may be on the conservative side and possibly understates the amount of interest income VENCorp will earn over the forthcoming regulatory period.

Accumulated surplus

Pursuant to cl. 9.8.4C(e)(iii) of the NER, the AER must take into account any accumulated surplus or deficit from the current regulatory period in determining VENCorp's MAAR for the forthcoming regulatory period.

The AER understands that at the time VENCorp set its 2007-08 transmission charges, it was expecting an accumulated surplus at the end of 2006-07 of $26.61m (nominal). Accordingly VENCorp set its 2007-08 transmission charges with the aim of achieving a deficit of $26.61m (nominal) in 2007-08, and thus an accumulated surplus/deficit at the end of 2007-08 of zero.

VENCorp's financial accounts indicate that it in fact had an accumulated surplus of $49.80m (nominal) at the end of 2006-07, instead of the expected $26.61m (nominal). This appears to be the result of VENCorp receiving significantly more settlement residue than expected. As VENCorp's 2007-08 transmission charges are already set, it is still expected to achieve a deficit in 2007-08 of $26.61m (nominal). However, because VENCorp's accumulated surplus at the end of 2006-07 was greater than its forecast at the time charges were set, this is now expected to lead to an accumulated surplus of $25.19m (nominal) at the end of 2007-08, instead of the zero balance intended. VENCorp's assumption of a zero surplus is therefore incorrect.

The AER proposes to deduct the full amount of VENCorp's 2007-08 accumulated surplus from its MAAR in 2008-09. This is consistent with the approach that VENCorp itself follows in setting its transmission charges each year.

AIS rebate allowance

As noted above, when VENCorp submitted its revised proposal it stated its intention to remove the AIS rebate allowance from its forecast of prescribed services charges, as SP AusNet had already sought an allowance for these rebates in its revenue proposal. While VENCorp removed the allowance from its prescribed services

[20] VENCorp, *op cit*, p. 40.

charges forecast, it did not remove the allowance from the overall MAAR presented in the reconciliation document.

The AER has corrected the error in VENCorp's calculations. The MAAR determined by the AER for VENCorp does not include a separate allowance for AIS rebates. This is covered in the prescribed services charges for the allowance given to SP AusNet.

MAAR

The table below sets out the AER's draft decision on the determination of VENCorp's MAAR for each financial year of the forthcoming regulatory period, as required by cl 9.8.4C(e)(4).

Table 9: AER's draft decision – MAAR ($m, nominal)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
Operating expenditure	5.99	6.20	6.43	6.67	6.91	7.17	**39.37**
Committed augmentation charges	19.35	19.93	20.53	21.14	21.78	22.43	**125.16**
Planned augmentation charges	0.37	1.01	5.16	10.67	15.25	13.72	**46.18**
Total VENCorp expenditure	**25.70**	**27.14**	**32.12**	**38.48**	**43.94**	**43.31**	**210.71**
Prescribed services charges	373.57	392.16	410.86	431.35	451.94	474.53	**2 534.41**
minus Interest income	-1.00	-1.00	-1.00	-1.00	-1.00	-1.00	**-6.00**
minus Accumulated surplus	-25.19	-	-	-	-	-	**-25.19**
MAAR	**373.08**	**418.30**	**441.98**	**468.84**	**494.88**	**516.85**	**2 713.93**

Source: VENCorp, AER analysis

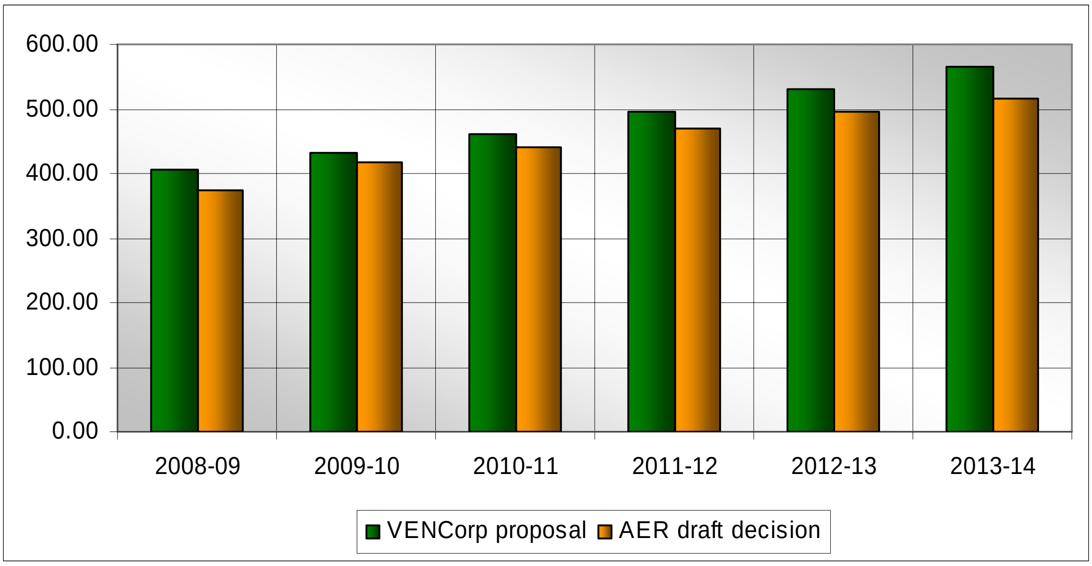
In VENCorp's revised proposal, VENCorp proposed a total MAAR of $2 889.80m (nominal), over the forthcoming regulatory period. The AER has made a total reduction of $175.87m (nominal) to this amount, resulting in a total MAAR of $2713.93m (nominal).

Table 10: AER's draft decision – MAAR ($m, nominal)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
VENCorp's proposal	405.00	430.50	462.00	496.70	529.90	565.70	2 889.80
AER's adjustment	-31.92	-12.20	-20.02	-27.86	-35.05	-48.85	-175.87
AER's draft decision	**373.08**	**418.30**	**441.98**	**468.84**	**494.88**	**516.85**	**2713.93**

Source: VENCorp, AER analysis

Figure 5 AER's draft decision – MAAR ($m, nominal)



Source: VENCorp, AER analysis

Indicative price path

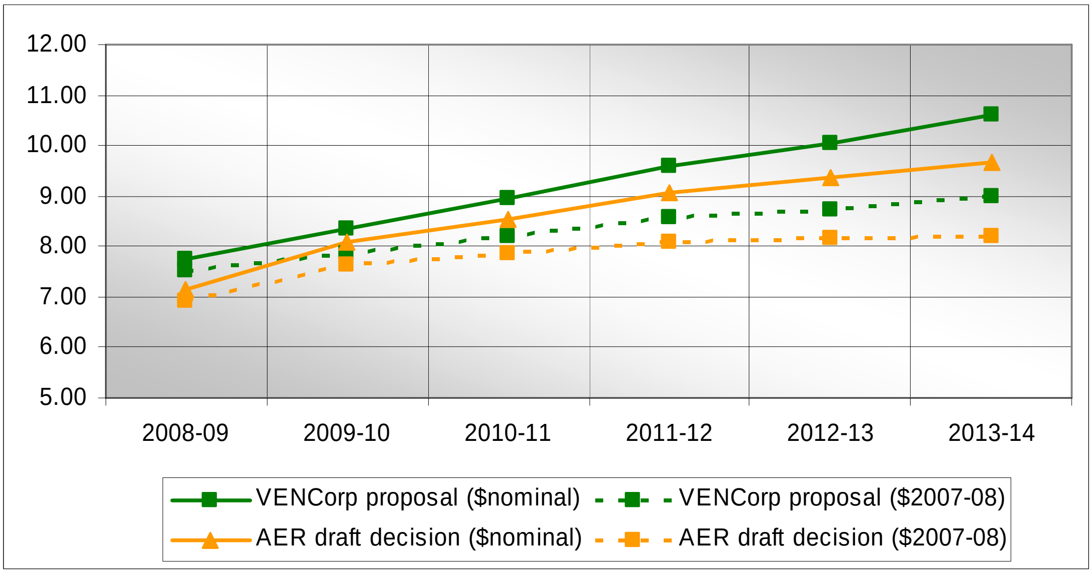
The following indicative TUOS price path is based on the AER's draft decision on VENCorp's MAAR, and the demand forecasts contained in VENCorp's proposal.

Table 11: AER's draft decision – Indicative TUOS price path ($/Mwh)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Average
VENCorp's proposal ($nominal)	7.74	8.33	8.94	9.59	10.04	10.60	**9.21**
VENCorp's proposal ($2007-08)	7.51	7.86	8.20	8.56	8.73	8.98	**8.31**
AER's draft decision ($nominal)	7.13	8.10	8.55	9.05	9.38	9.68	**8.65**
AER's draft decision ($2007-08)	6.92	7.64	7.85	8.08	8.15	8.20	**7.81**

Source: VENCorp, AER analysis

Figure 6: AER's draft decision – Indicative TUOS price path ($/Mwh)



Source: VENCorp, AER analysis

Negotiating framework

VENCorp is required to submit to the AER a proposed negotiating framework setting out the procedure to be followed by VENCorp and a service applicant during negotiations for a negotiated transmission service. The minimum requirements for a negotiating framework are set out at cl. 6A.9.5(c) of the NER.

The AER is required to determine in its draft decision whether the proposed negotiating framework submitted by VENCorp is consistent with the requirements of the NER. Where the proposed negotiating framework meets the requirements of the NER, the AER must approve the framework. Where the proposed negotiating framework does not satisfy the minimum requirements, then the framework must not be approved and the AER must specify in its draft decision the changes necessary to make the proposed framework compliant with the minimum requirements of the NER.[21]

AER's conclusion

The AER has found only one aspect of VENCorp's proposed negotiating framework that is not compliant with the requirements of cl. 6A.9.5(c). In requiring the payment of a minimum application fee, the AER considers that VENCorp's negotiating framework must also provide for any difference between that fee and costs reasonably incurred by VENCorp to be refunded if the requirement is to remain consistent with cl. 6A.9.5(c)(7) of the NER.

The AER therefore requires VENCorp to amend its proposed negotiating framework to correct this area of non-compliance. Details of the changes required are discussed further in chapter 6 of this draft decision. The changes themselves are set out in appendix B. In requiring these changes, the AER has amended the negotiating

[21] NER cl. 6A.12.1(d)

framework only to the extent necessary to make the proposed framework consistent with the requirements of the NER.

Negotiated transmission service criteria (NTSC)

The AER must determine the NTSC to be applied by VENCorp in negotiating the terms and conditions of access, including price, for negotiated transmission services. In the event of a dispute between VENCorp and a service applicant, a commercial arbitrator must also apply the NTSC.

VENCorp is not required to submit proposed negotiating criteria to the AER. The AER must determine criteria for VENCorp in accordance with the NER, which give effect to, and are consistent with, the negotiated transmission services principles set out in cl. 6A.9.1 of the NER.

AER's conclusion

The negotiating criteria set out in appendix C will apply to VENCorp for the 2008-2014 regulatory control period. The negotiating criteria give effect to the negotiated transmission service principles contained in cl. 6A.9.1, under the umbrella of a requirement that the negotiated terms and conditions of access, including the price to be charged for the provision of negotiated services and any access charges, promote the achievement of the national electricity market objective.

The NER contemplate NTSC that will apply to a particular TNSP, and (subject to consistency with the negotiated transmission service principles) allow the AER the flexibility to include additional and potentially unique criteria where necessary. The AER has not identified any particular circumstances that would warrant the inclusion of additional criteria other than those based on the negotiated transmission service principles for the purposes of this determination.

Pricing Methodology

VENCorp submitted its proposed pricing methodology to the AER on 12 June 2007 stating that it gave effect to and was consistent with the pricing principles in cl. 6A.23 and the agreed interim arrangements that applied to VENCorp's proposal under the transitional arrangements published by the AER in February 2007.

On 29 October 2007, the AER published its final pricing methodology guidelines. As permitted under the interim arrangements, VENCorp notified the AER on 11 November 2007 that it wished to have its proposed pricing methodology assessed against the final guidelines.

AER's conclusion

The AER has assessed VENCorp's proposed pricing methodology against the final pricing methodology guidelines. VENCorp's proposed methodology was developed under the agreed interim arrangements, prior to the release of both the draft and final pricing methodology guidelines. VENCorp's methodology therefore refers to NER requirements that are no longer relevant and does not contain information that is prescribed under the AER's pricing guidelines. Certain amendments are therefore required before the AER can approve the methodology under those guidelines.

The AER has not approved the proposed pricing methodology. Under the agreed interim arrangements VENCorp must submit a revised pricing methodology to the AER by 14 December 2007. The revised proposed pricing methodology will be published for consultation at that time.

1 Introduction

1.1 Background

The Australian Energy Regulator (AER) is responsible for the economic regulation of monopoly transmission services in the National Electricity Market (NEM). These functions were conferred on the AER by the National Electricity Law (NEL) and the National Electricity Rules (NER) on 1 July 2005.

The AER must make transmission determinations for Transmission Network Service Providers (TNSPs) in respect of prescribed and negotiated transmission services in accordance with the NER.

VENCorp's current revenue cap for the five and a half year period from 1 January 2003 to 30 June 2008 was determined by the ACCC in December 2002, and varied in 2004.

On 1 March 2007, VENCorp submitted its revenue proposal and proposed negotiating framework for the 1 July 2008 to 30 June 2014 regulatory period. VENCorp's pricing methodology was submitted separately on 7 June 2007.

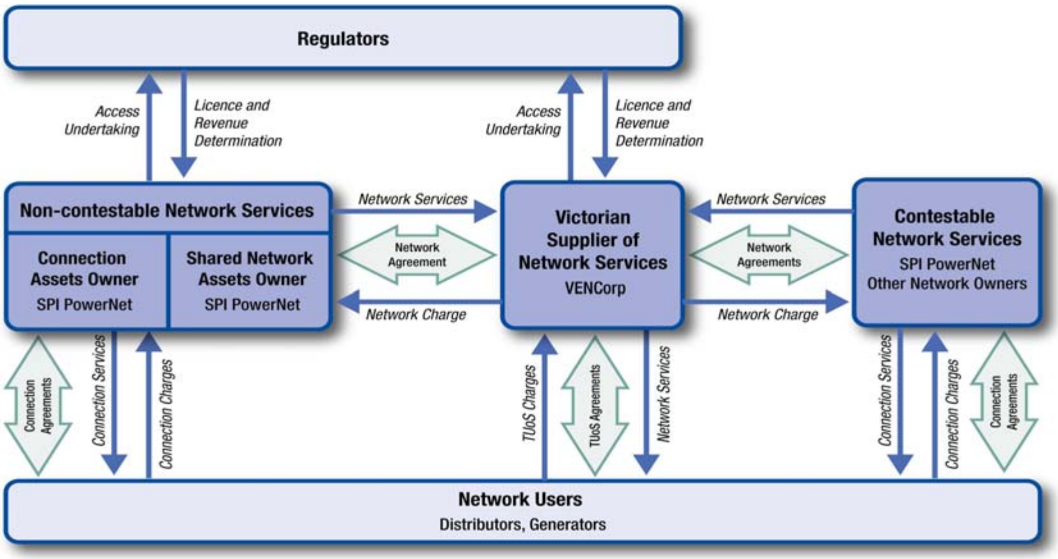
On 21 June 2007, VENCorp published its 2007 Electricity Annual Planning Report (2007 EAPR). At the AER's request, VENCorp submitted a reconciliation of its revenue proposal (the initial proposal) and the 2007 EAPR on 19 July 2007. The reconciliation presented a revised forecast of planned augmentation expenditure and planned augmentation charges, and a recalculation of VENCorp's proposed maximum allowable revenue (MAAR). For the purposes of this draft decision, VENCorp's initial proposal as amended by the new information provided in the reconciliation is referred to as the revised proposal. The AER's draft decision has been made on this revised proposal.

1.2 Overview of the VENCorp and SP AusNet transmission network

The transmission arrangements in Victoria, which separate the network asset owner (predominately SP AusNet) from the investment decision-maker (VENCorp), are unique in the NEM. SP AusNet owns and operates the transmission network and provides bulk transmission services to VENCorp under a network services agreement. VENCorp owns no transmission assets itself. It provides shared network services to users and is responsible for planning and directing the augmentation of the shared network (which excludes the connection facilities utilised by generators and distribution bodies).

Figure 1.1 below illustrates the commercial arrangements for transmission investment decision-making in Victoria.

Figure 1.1 Commercial arrangements for the provision of electricity transmission services

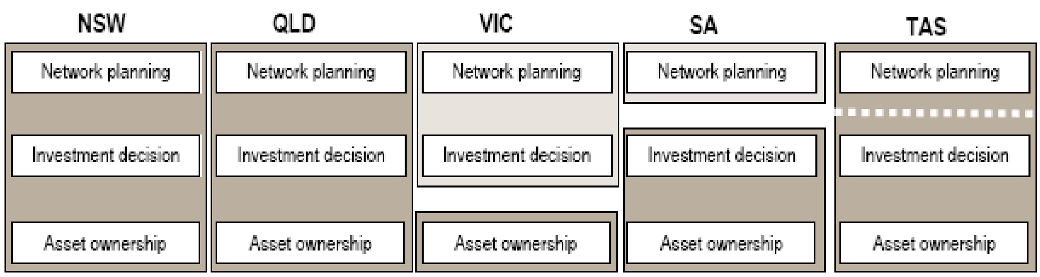


Source: SP AusNet revenue proposal, 28 February 2007

1.2.1 VENCorp

The Victorian Energy Networks Corporation (VENCorp) is a statutory corporation wholly owned by the Victorian government. As illustrated in figure 1.2, the functions and operations of VENCorp differ to those of TNSPs in other states, where planning and responsibility for augmentation is generally undertaken by one transmission company.[22]

Figure 1.2 Structural separation of network planning and asset ownership



Source: VENCorp revenue proposal, 1 May 2007

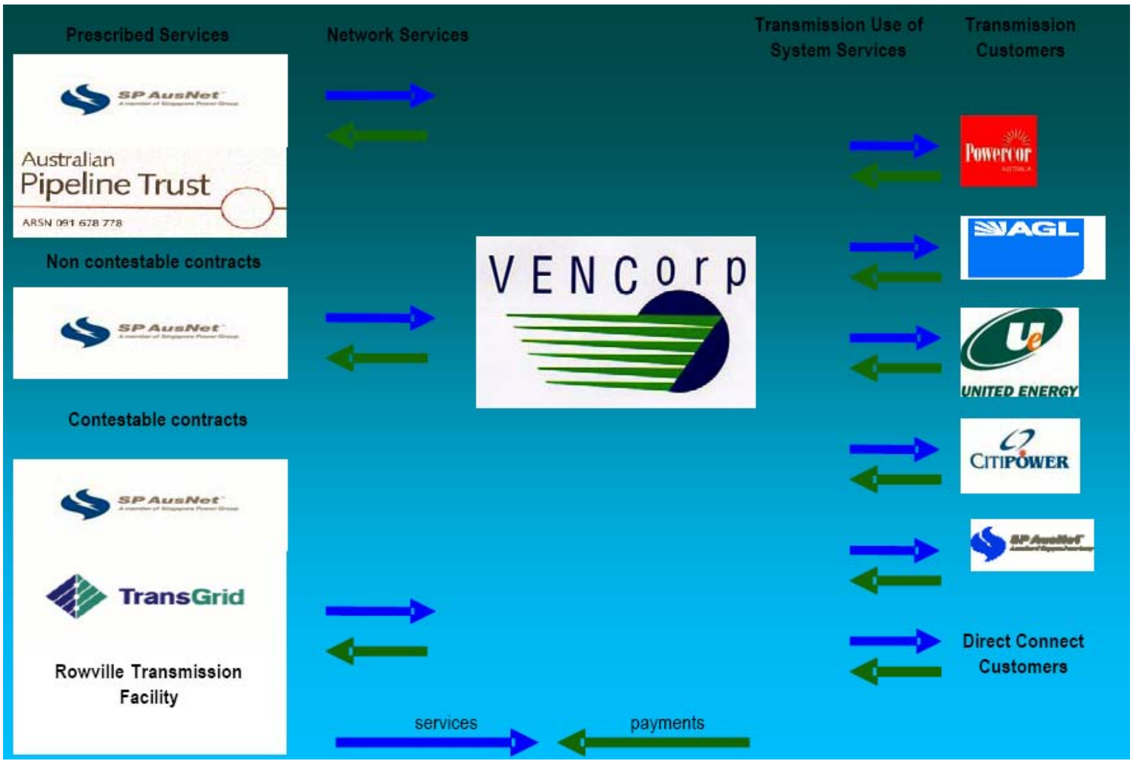
In Victoria, VENCorp is the monopoly provider of shared transmission network services, acquiring bulk network services from SP AusNet and other service providers under network agreements. VENCorp also plans and directs the augmentation of the shared network. VENCorp does not own transmission assets itself, and by operation

[22] With the exception of South Australia where ESIPC is the planning body responsible for planning augmentations to the South Australian network, but does not have the same investment decision making function as VENCorp.

of the jurisdictional derogation for Victoria in Chapter 9, Part A of the NER, its revenue determination is made on a full cost recovery but no operating surplus basis.

Figure 1.3 below illustrates the flow of services and payments between VENCorp, service providers and users.

Figure 1.3 – Service provision and financial flows



Source: VENCorp revenue proposal, Initial Public Forum Presentation, 10 May 2007

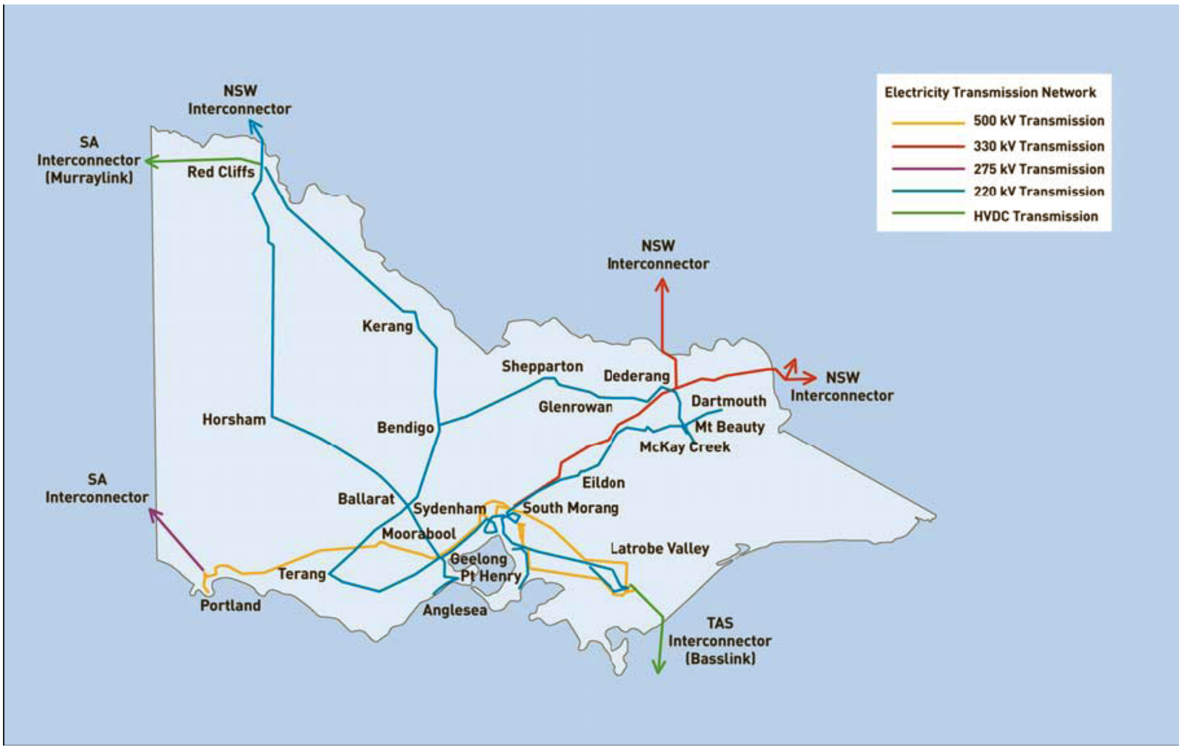
1.2.2 SP AusNet network

SP AusNet owns, operates and maintains over 6 500 kilometres of high voltage transmission lines, spanning approximately 227 600 square kilometres throughout Victoria. The network serves over 1.8 million households and 280 000 businesses, transporting in excess of 45 million MWh of energy each year.

As figure 1.4 illustrates, the network is built around a 500kV backbone running from the major generating source in the Latrobe Valley, through Melbourne and across the southern part of the state to Heywood, near the South Australian border. This backbone is designed to support the major load centres (Melbourne and the Portland aluminium smelter) and is surrounded by:

- a 220 kV ring around the Melbourne metropolitan area supplying 220 kV/66 kV terminal stations
- an inner and outer ring of 220 kV/66 kV terminal stations in country Victoria supplying the regional centres (the “State Grid”)
- interconnections with NSW, South Australia and Tasmania.

Figure 1.4: SP AusNet's transmission network

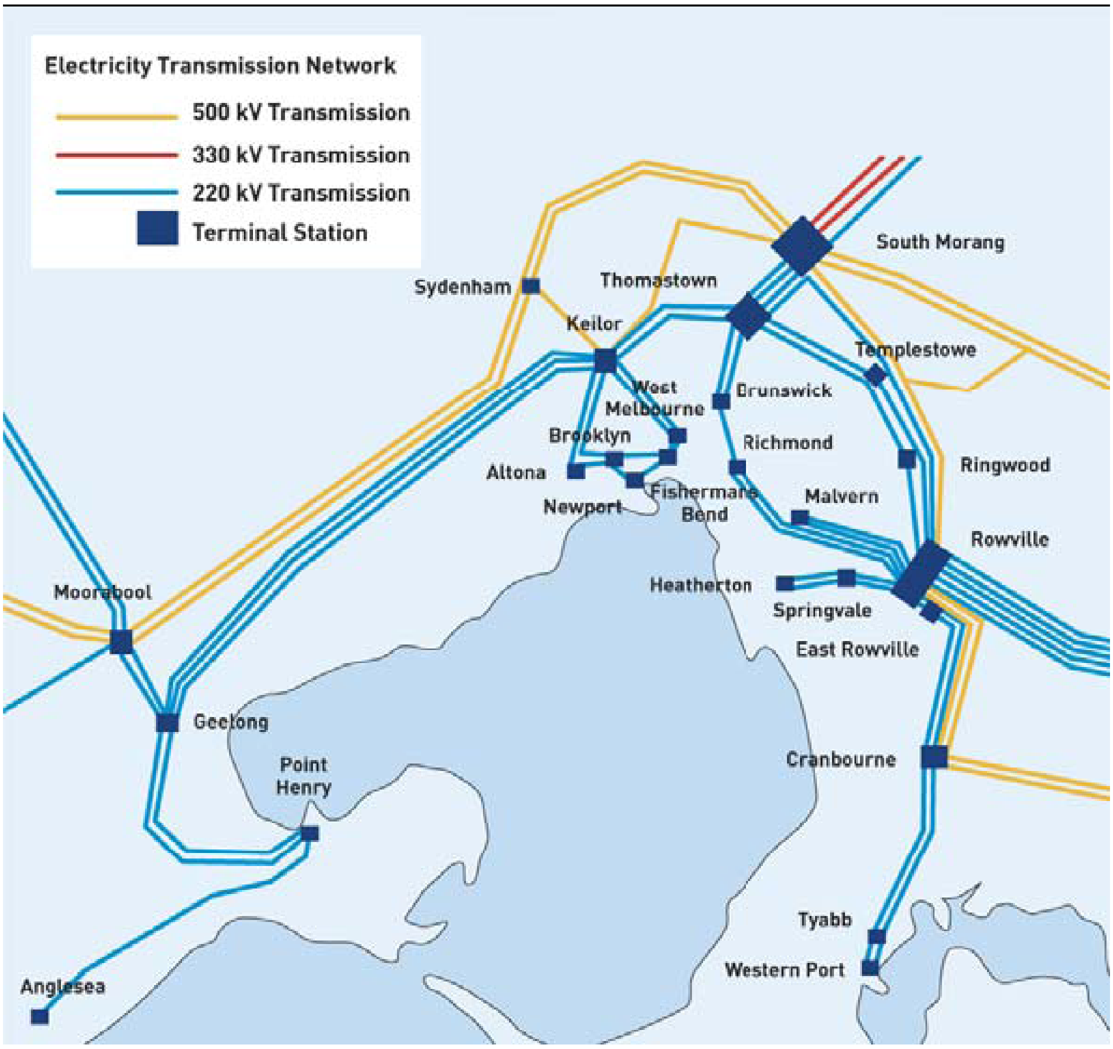


Source: VENCorp revenue proposal, 1May 2007

Melbourne's metropolitan area (figure 1.5) is served by 500 kV and 220 kV networks which receive power from generators in the Latrobe Valley, Victorian hydro-electric power stations, a gas-fired power station at Newport and the interconnections with NSW, SA and Tasmania:

- the Latrobe Valley to Melbourne link comprises four 500 kV lines supplying power from Loy Yang and Hazelwood power stations to Keilor, South Morang, Rowville and Cranbourne Terminal Stations, and six 220 kV lines transferring power from the Yallourn and Hazelwood generation units into the eastern metropolitan area at Rowville Terminal Station
- supply from NSW and the Snowy Mountains generators is through two 330 kV lines from Dederang Terminal Station in the north east to South Morang Terminal Station on the northern perimeter of Melbourne
- the Southern Hydro generators at Kiewa, Eildon and Dartmouth are connected to Thomastown Terminal Station via a 220 kV system
- Springvale, Heatherton, East Rowville, Tyabb and Malvern Terminal Stations derive their supply from radial single tower, double-circuit 220 kV lines to minimise the amount of land required for transmission in the metropolitan area and
- 220 kV links between Newport Power Station and Fishermen's Bend Terminal Stations, and Brunswick and Richmond Terminal Stations, increase supply routes for Melbourne's inner suburbs and the central business district.

Figure 1.5: SP AusNet's transmission network – Metropolitan Melbourne



Source: SP AusNet, August 2007

1.3 Regulatory requirements

The requirements for VENCorp's transmission determination are set out in the NER, in chapter 6A and the jurisdictional derogation for Victoria in Chapter 9, Part A (the derogation). Chapter 6A of the NER commenced in November 2006, and applies to all TNSPs in the National Electricity Market (NEM). The derogation, which was amended with the commencement of the new chapter 6A, modifies the application of chapter 6A to TNSPs in Victoria, and to VENCorp in particular. While the development of the new chapter 6A was undertaken by the AEMC, the nature of the derogation itself was outside the scope of the AEMC's review.

The NER divides transmission services into three categories:

- prescribed transmission services, which are subject to revenue determinations by the AER, and directly regulated under this mechanism

- negotiated transmission services, the terms and conditions of which (including price of the services) are determined by commercial negotiation (and if necessary arbitration) in accordance with a negotiating framework proposed by a TNSP and approved by the AER, and Negotiated Transmission Services Criteria determined by the AER and
- non-regulated transmission services, which are not subject to regulation.

The AER is required to make a transmission determination for a TNSP that includes:

- a revenue determination for the service provider in respect of prescribed transmission services
- a determination relating to the provider's negotiating framework
- a determination specifying the negotiated transmission service criteria that apply to the provider and
- a determination specifying the pricing methodology for prescribed transmission services to apply to the service provider.

The application of chapter 6A in respect of the Victorian Transmission Network or a part of the Victorian Transmission Network is subject to the modifications set out in clauses 9.8.4B to 9.8.4F of the jurisdictional derogation for Victoria. These modifications are intended to accommodate the unique Victorian transmission model discussed above.

Chapter 6A is not displaced by clauses 9.8.4B to 9.8.4F. The provisions of chapter 6A continue to apply to VENCorp, but are modified by the derogations in chapter 9.[23] The extent and effects of these modifications are summarised in the sections below as they impact upon each element of the AER's transmission determination for VENCorp.

1.3.1 Revenue determination

The AER's consideration of VENCorp's revenue proposal is set out in chapters 2 to 5 of this draft decision and in detailed appendices A and B.

There are a number of differences in terminology between the derogation in Chapter 9 and Chapter 6A:

- references in chapter 6A to a Transmission Network Service Provider are to be read as a reference to VENCorp
- references to the maximum allowable revenue (MAR) for a Transmission Network Service Provider for a regulatory year of a regulatory control period is to be read as a reference to the maximum allowable aggregate revenue (MAAR)

[23] NER cll. 9.8.4A; 9.8.4B(a)(2)

- references to prescribed transmission services are to be read as references to services in respect of which VENCorp may determine shared transmission network use charges.[24]

The AER's revenue determination for VENCorp is a determination of VENCorp's MAAR in respect of those services for which VENCorp may determine shared transmission network use charges. This compares to revenue determinations for all other TNSPs, which takes the form of the MAR in respect of prescribed transmission services.

Under cl. 9.8.4C(d) and (e)(4), the AER must determine VENCorp's MAAR for a relevant regulatory period. The AER's determination under cl. 9.8.4C(d) must set out the MAAR for each financial year of the relevant regulatory period.[25]

The derogation requires that:

- the amount of VENCorp's MAAR for a relevant regulatory period must not exceed VENCorp's statutory electricity transmission related costs.[26]
- VENCorp's MAAR must be determined on a full cost recovery but no operating surplus basis.[27]

For the relevant regulatory period, VENCorp's statutory electricity transmission related costs are:[28]

1. VENCorp's aggregate actual costs in operating and planning the Victorian Transmission Network;
2. all network charges payable by VENCorp to SP AusNet or any other owner of the Victorian Transmission Network or a part of the Victorian Transmission Network, including charges relating to augmentations;
3. all other charges payable by VENCorp to providers of network support services and other services which VENCorp uses to provide network services that are transmission services; and
4. any other costs that directly arise out of VENCorp's functions under the *Electricity Industry Act 2000* (Vic) relating to the transmission of electricity, the application of the Rules to VENCorp or the conditions imposed on VENCorp under its transmission licence relating to the transmission of electricity, for which there is no alternative method (legislative or contractual) for the recovery of those costs.

The AER's determination of VENCorp's MAAR:

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[24] NER cl. 9.8.4B(a)(2)
[25] NER cl. 9.8.4C(e)(4)
[26] NER cl. 9.8.4C(a)(1)
[27] NER cl. 9.8.4C(a)(2)
[28] NER cl. 9.3.1

- must comply with the requirements set out in clause 6A.14.2 relating to the AER's reasons for its decision, modified as necessary to apply to the revenue regulatory regime under cl. 9.8.4C[29]
- must take into account VENCorp's functions under the Electricity Industry Act 2000 (Vic), the application of the NER to VENCorp and the conditions imposed on VENCorp under its transmission licence[30]
- must take into account any difference between VENCorp's most recent forecasts of the revenue that it will recover by way of shared transmission network use charges and its statutory electricity transmission related costs and, where such a difference exists (in the form of an accumulated surplus or deficit), must apply that difference in the form of a negative or a positive adjustment to VENCorp's MAAR.[31]

The nature of VENCorp's role, and the operation of the Victorian jurisdictional derogation, means that the determination of VENCorp's MAAR differs in a number of respects to the determination of maximum allowed revenue (MAR) for other TNSPs. In particular, the operation of the derogation means that the components of VENCorp's revenue determination differ to the building blocks for other TNSPs.

VENCorp's MAAR is the total of VENCorp's opex, planned augmentation charges, committed augmentation charges and prescribed service charges payable to SP AusNet and Murraylink for the provision of prescribed services by those TNSPs, adjusted for any surplus accumulated in the current regulatory period.

For each year of the relevant regulatory period, VENCorp's total revenue requirement is calculated as:

Operating expenditure	
Committed augmentation charges	
Planned augmentation charges	+
= Total forecast expenditure	
Prescribed services charges	+
Interest income	-
Accumulated surplus (2002-08)	-
= Total revenue requirement	

Each of these building blocks is discussed briefly below.

29 NER cl. 9.8.4C(e)(2)
30 NER cl. 9.8.4C(e)(3)(i)
31 NER cll. 9.8.4C(e)(3)(iii), 9.8.4C(f)

Adjustments to MAAR

The AER notes that under cl. 9.8.4C(g2) of the derogation if, over VENCorp’s forthcoming regulatory period, VENCorp’s statutory electricity transmission-related costs for a financial year exceed, or VENCorp anticipates they will exceed, the amount of the statutory transmission-related costs for that financial year assumed by the AER in determining VENCorp’s MAAR, VENCorp may apply to the AER for an adjustment to its MAAR for each affected financial year in the forthcoming regulatory period of an amount equal to the amount required to ensure that its MAAR complies with the following principles:

- VENCorp’s MAAR must not exceed VENCorp’s statutory electricity transmission-related costs, and
- VENCorp’s MAAR must be determined on a full cost recovery but no operating surplus basis.

Following an application by VENCorp to adjust its MAAR, the AER must determine the amount, if any, by which VENCorp’s MAAR for each affected financial year in the forthcoming regulatory period is to be adjusted so that it complies with the above principles.

This provision is not symmetrical, in that VENCorp is not required to make an application to the AER should its statutory electricity transmission-related costs be less than VENCorp’s MAAR in any financial year.

The AER notes that the availability of this re-opening mechanism is not a consideration relevant to the determination of VENCorp’s MAAR for the purposes of this draft decision.

1.3.1.1 Operating expenditure

Unlike other TNSPs, VENCorp does not own transmission assets, or undertake maintenance to a transmission network. VENCorp’s forecast operating expenditure (opex) does not relate to routine maintenance or other analogous costs that would be included in the opex forecasts of other TNSPs. VENCorp’s forecast opex is only comprised of corporate related costs.

The AER’s assessment of the forecast of opex that VENCorp proposes be included in its MAAR under cl. 6A.6.6 of the NER has been made in the context of cl. 9.8.4C(a), which requires the MAAR and therefore its building blocks to be set on a full cost recovery, no operating surplus basis

The AER’s consideration of VENCorp’s forecast opex is set out in chapter 2 of this draft decision.

1.3.1.2 Committed augmentation expenditure

VENCorp has no regulatory asset base (RAB) and does not incur capital expenditure (capex) in the same way as other TNSPs – it is a procurer of services. As such, where other TNSPs report past capex to be rolled into their regulatory asset bases, VENCorp incurs committed augmentation expenditure in the form of contract prices for augmentations which will be payable over future regulatory periods (committed augmentation charges).

Provided that the costs incurred by VENCorp fall within the definition of statutory electricity transmission related costs, the operation of the derogation is such that the AER has no role in assessing the prudency or efficiency of costs that VENCorp has already incurred, or in determining the extent to, or the manner in which those costs can be recovered from users. The AER's determination must allow committed augmentation charges associated with contracts entered into in, and prior to, the current regulatory control period (prudent or otherwise) to be recovered in full. The approved forecast of committed augmentation charges payable in the forthcoming regulatory period is one of the building blocks of VENCorp's MAAR. In assessing VENCorp's forecast committed augmentation charges for the forthcoming regulatory period, the AER's task is to determine whether that forecast reasonably reflects a realistic expectation of the committed augmentation charges that VENCorp will incur in that period.

The AER's consideration of VENCorp's forecast committed augmentation charges is set out in chapter 3 of this draft decision.

1.3.1.3 Planned augmentation expenditure

Where other TNSPs forecast capex, VENCorp derives a forecast of the contract charges that will be payable in the relevant regulatory period in respect of new contracts entered into for planned augmentations, on the basis of an indicative planned augmentation expenditure forecast.

VENCorp's forecast planned augmentation charges are derived from an underlying forecast of planned augmentations which VENCorp submits are likely to occur within the forthcoming regulatory period, and estimates of the associated capital costs. These forecast costs are converted to forecast planned augmentation charges on the basis of a series of assumptions (WACC, depreciation over the life of a contract, associated opex) based on recent regulatory decisions and VENCorp's past experience in contracting for similar works.

The AER's review of VENCorp's forecast planned augmentation charges involves a review of:

- the forecast planned augmentation expenditure from which they have been calculated,
- the methodology applied in calculating forecast charges on the basis of the forecast of expenditure, and
- the resultant forecasts.

The AER's assessment of the forecast of planned augmentation charges that VENCorp proposes be included in its MAAR under cl. 6A.6.7 of the NER has again been made in accordance with cl. 9.8.4C(a), so that the MAAR built on that forecast is set on a full cost recovery, no operating surplus basis.

VENCorp's forecast of planned augmentation expenditure does not identify any projects that should be treated as contingent projects under cl. 6A.8.1 of the NER. Rather, VENCorp will seek to reopen its MAAR under cl. 9.8.4C (g2) of the NER if its statutory electricity-transmission related costs exceed, or are expected to exceed, the amount assumed by the AER in making its determination.

The AER's consideration of VENCorp's planned augmentation expenditure and charges is set out in chapter 4 and appendix A of this draft decision.

1.3.1.4 Prescribed service charges

VENCorp's prescribed service charges are payments made by VENCorp to SP AusNet and Murraylink for the provision of shared transmission services. VENCorp's forecast prescribed service charges for the Murraylink interconnector are based on the AER's revenue cap of 1 October 2003. VENCorp's forecast prescribed service charges for SP AusNet are based on SP AusNet's revenue proposal to the AER for its 2008-14 regulatory control period, and will ultimately be set on the basis of the AER's final decision on SP AusNet's transmission determination. For the purposes of this draft decision, they will be based on the AER's draft decision on SP AusNet's transmission determination, which was released on 31 August 2007.

1.3.1.5 Interest income

The MAAR is also adjusted to account for interest income earned by VENCorp in a regulatory period.

1.3.1.6 Accumulated surplus/deficit

In its revenue proposal, VENCorp must submit a statement reconciling its most recent forecast of the revenue that will be recovered by way of shared transmission network use charges, and the statutory electricity transmission-related costs, for the relevant regulatory period immediately preceding the regulatory period to which the application relates.

If there is a difference in the forecasts of revenue that will be recovered by way of shared transmission network use charges and statutory electricity transmission-related costs for the preceding regulatory period, then the AER must apply that difference in its determination of VENCorp's MAAR by adjusting it to remove any accumulated surplus or deficit as appropriate. This takes the form of a lump sum adjustment to VENCorp's MAAR for the first financial year of the forthcoming regulatory period.

1.3.1.7 Service target performance incentive scheme and opex efficiency benefit sharing scheme

The AER's service target performance incentive scheme and opex efficiency benefit sharing scheme do not apply to VENCorp. VENCorp is not subject to any form of performance incentive under the NER.

The AER's consideration of VENCorp's proposed MAAR is set out in chapter 5 of this draft decision.

1.3.2 Negotiating framework

VENCorp must prepare a negotiating framework, setting out the procedure to be followed during negotiations between VENCorp and any person who wishes to receive a negotiated transmission service from VENCorp, as to the terms and conditions of access for provision of the service.

The AER's determination on the negotiating framework must set out any requirements that are to be complied with in respect of the preparation, proposal or operation of the VENCorp's negotiating framework.

The AER's consideration of VENCorp's proposed negotiating framework is set out in chapter 6 of the draft decision, and in detailed appendix B.

1.3.3 Negotiated transmission service criteria

The Negotiated Transmission Service Criteria (NTSC) forming part of the transmission determination for VENCorp are the criteria that are to be applied:

1. by VENCorp in negotiating:
    - the terms and conditions of access for negotiated transmission services, including the prices that are to be charged for the provision of those services by VENCorp for the relevant regulatory control period, and
    - any access charges which are negotiated by VENCorp during that regulatory control period; and
2. by a commercial arbitrator in resolving any dispute between VENCorp and a person who wishes to receive a negotiated transmission service, in relation to:
    - the terms and conditions of access for the negotiated transmission service, including the price that is to be charged for the provision of that service by VENCorp and
    - any access charges that are to be paid to or by VENCorp.

The NTSC must give effect to and be consistent with the Negotiated Transmission Service Principles as set out in the NER.

The AER's determination of the NTSC that will apply to VENCorp is set out in chapter 7 of the draft decision, and in appendix C.

1.3.4 Pricing methodology

VENCorp must comply with the pricing methodology approved by the AER, and other applicable requirements in the NER, when setting the prices that may be charged for the provision of prescribed transmission services.

The pricing methodology proposed by VENCorp and approved by the AER must give effect to and be consistent with the pricing principles for prescribed transmission services set out in part J of the NER, and comply with the requirements of, and contain or be accompanied by such information as is required by, the pricing methodology guidelines made for that purpose by the AER.

Chapter 9 modifies the operation of Part J chapter 6A as it applies to VENCorp regarding the pricing for the provision of prescribed transmission services. Under cl. 9.8.4F:

- the allocation of the aggregate annual revenue requirement as determined under cl. 9.8.4C, and

- the allocation of transmission costs and the conversion of those allocated transmission costs to prescribed transmission service prices and charges, as provided for under Part J of chapter 6A

must reflect the arrangements in place in relation to the Victorian Transmission Network or a part of the Victorian Transmission Network under the *Electricity Industry Act 2000* (Vic), the *Essential Services Commission Act 2001* (Vic) and the Tariff Order[32].

The AER's consideration of VENCorp's proposed pricing methodology is set out in chapter 8 of the draft decision, and in detailed appendix D.

1.4 Transitional arrangements – transmission guidelines

The Australian Energy Market Commission (AEMC) commenced a review of the rules for economic regulation of electricity transmission networks in the NEM during mid 2005. The new chapter 6A of the NER was released in November 2006. The NER require the AER to publish several transmission guidelines in September and October 2007.

As VENCorp lodged its proposal on 1 March 2007 before the AER's final guidelines were developed, transitional provisions were included in chapter 11 of the NER. For the purposes of making a 2008 determination, these provisions require anything that must be done in accordance with a guideline to be done in accordance with the corresponding proposed guideline.[33] In particular:

- the Submission Guidelines that apply to VENCorp are the First Proposed Submission Guidelines released by the AER on 31 January 2007
- the Cost Allocation Guidelines that apply to VENCorp are the First Proposed cost allocation guidelines released by the AER on 31 January 2007[34]
- VENCorp's proposed pricing methodology was submitted under the AER's agreed interim requirements, released 16 February 2007, but will at VENCorp's election be considered under the final pricing guidelines released on 29 October 2007.

The proposed guidelines will apply to VENCorp until the end of the 2008–2014 regulatory period covered by the AER's 2008 transmission determination.

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32 Tariff means an Order made under section 15A of the *Electricity Industry Act 2000* (Vic) as that Order is amended and in force from time to time.

[33] NER cl. 11.6.18

[34] For the purposes of making a 2008 determination for the regulatory control period to be covered by a 2008 determination, a relevant provider is taken to have complied with a requirement to comply with a Cost Allocation Methodology under the new chapter 6A if the AER is satisfied that the relevant provider has complied with the relevant proposed guideline for cost allocation referred to in cl. 11.6.17(a)(6), but only until the AER has approved a Cost Allocation Methodology for that provider under cl. 6A.19.4.

1.5 Length of regulatory period

A revenue determination must specify the commencement and length of the regulatory period to which it applies. The regulatory period must not be less than five regulatory years. The AER must approve the commencement and length of the regulatory period as proposed by the TNSP on its revenue proposal if the length proposed is five regulatory years, but is not precluded from approving a longer period if that is proposed by the TNSP.

SP AusNet has proposed a six-year regulatory control period commencing on 1 April 2008, and ending on 31 March 2014. This extended period is proposed as a way to smooth SP AusNet's future workload by separating its electricity transmission and gas distribution reviews. In order to be consistent with SP AusNet , VENCorp has also proposed a six-year regulatory control period commencing 1 July 2008 to 30 June 2014.

The AER has accepted the proposed duration of the regulatory control period as a once-off measure to address the issues of regulatory burden identified by SP AusNet.

1.6 Review process

Under the derogations, the process and timing for the making of VENCorp's transmission determination are considerably modified. Chapter 9 provides for an abbreviated, single-stage process for all aspects of VENCorp's transmission determination, with the exception of its pricing methodology. However, in the interests of consistency with the process to be followed by SP AusNet, and to facilitate the input of interested parties, the AER requested, and VENCorp agreed, to submit its proposal at the same time as SP AusNet, enabling the AER to publish and consult on this draft decision.

To date, the AER's review process has involved:

Submission of revenue proposal, 2007 EAPR, and revised proposal

VENCorp's initial proposal was submitted to the AER on 1 March 2007, and resubmitted on 1 May 2007 following the AER's preliminary examination and determination of non-compliance under cl. 6A.11.1. For the purposes of this draft decision, the 1 May 2007 proposal is referred to as the "initial proposal". It is the initial proposal that was published for consultation, and in response to which interested parties were invited to make submissions.[35]

On 21 June 2007 VENCorp published its 2007 EAPR. The report contained revisions to VENCorp's demand forecasts, costs estimates, and planned augmentation program which considerably deviated from its initial proposal.

On 19 July 2007 VENCorp provided the AER with a reconciliation of its initial proposal and the 2007 EAPR. The reconciliation document, which is available on the AER's website, presents revised forecasts of planned augmentation expenditure

[35] Only two submissions were received, from Transend and the Energy Users' Coalition of Victoria.

derived from the 2007 EAPR, revised forecast planned augmentation charges and prescribed service charges, and a revised proposed MAAR. The other components of VENCorp's initial proposal remain the same. In this draft decision, the initial proposal as amended by the reconciliation is referred to as the "revised proposal".

The AER's draft decision has been based on the revised proposal.

The opportunity to update or revise a revenue proposal after it has been submitted and consultation has commenced is not contemplated in either the derogation or chapter 6A. The AER was able to give VENCorp this opportunity under the agreed, extended process settled prior to commencement of this review.

Consultation

VENCorp's proposal was published by the AER on 1 May 2007, and interested parties were invited to make submissions. A public forum on VENCorp's proposal was held on 10 May 2007, at which VENCorp gave a presentation on its proposal. Submissions on VENCorp's proposal were received from Transend and the Energy Users Coalition of Victoria.

On 22 June 2007, the AER published its proposed Negotiated Transmission Services Criteria for VENCorp, calling for submissions by 3 August 2007. Submissions were received from VENCorp and the Southern Generators.[36]

Draft decision

The AER's draft decision has been made in accordance with the relevant requirements of rule 6A.14, as modified by the derogation. The AER released this draft decision on 30 November 2007.

In making this draft decision the AER has considered all written submissions made in response to VENCorp's proposal and subsequent consultations.

The AER engaged technical consultants to provide independent, objective advice on VENCorp's revenue proposal:

- PB Strategic Consulting (PB) was engaged by the AER to provide independent engineering advice on VENCorp's committed augmentation expenditure, forecast planned augmentation expenditure, and forecast operating expenditure. PB's review was limited to VENCorp's initial proposal, and did not address the reconciliation of that proposal with the 2007 EAPR. PB has worked extensively with Australian regulatory bodies, providing strategic management services in the utility, infrastructure and energy sectors, focusing on areas of industry and regulatory reform, energy economics, strategic planning, project finance, valuations, and advice on mergers and acquisitions.
- Nuttall Consulting (NC) was engaged to provide additional expert engineering advice on VENCorp's proposal, and the impact of VENCorp's reconciliation of its initial proposal and the 2007 EAPR on PB's recommendations on the initial

[36] AGL, Flinders Power, International Power Australia, Loy Yang Power Marketing Management Company and TRUenergy.

proposal. Nuttall Consulting is a consultancy specialising in regulation and business strategy in the energy and utility sector, and offers over 10 years of consultancy experience in this field, having worked with governments, industry regulators and competition authorities, industry participants and investors, in numerous countries.

2 Operating and planning expenditure

2.1 Introduction

VENCorp is responsible for the planning, development and augmentation of the Victorian electricity transmission network, and for the provision of common services or network services that are transmission services.[37] The forecast operating expenditure (opex) in VENCorp's proposal relates to:

- VENCorp's aggregate forecast operating costs in planning the Victorian transmission network; and
- any other opex related costs that directly arise out of VENCorp's functions under the *Electricity Industry Act 2000* (Vic) relating to the transmission of electricity, the application of the National Electricity Rules (NER) to VENCorp or the conditions imposed on VENCorp under its transmission licence relating to the transmission of electricity, for which there is no alternative method (legislative or contractual) for the recovery of those costs.[38]

VENCorp's forecast opex is only comprised of corporate related costs. Unlike other TNSPs, VENCorp does not own transmission assets, nor does it undertake maintenance to a transmission network. Accordingly, VENCorp's forecast opex does not relate to routine maintenance or other analogous costs that would be included in the opex forecasts of other TNSPs.

This chapter considers VENCorp's forecast opex for the forthcoming regulatory period.

2.2 Regulatory requirements

The regime for the economic regulation of transmission services, contained in chapter 6A of the NER, and the jurisdictional derogation for Victoria, found in chapter 9, part A, of the NER, are both relevant to the AER's assessment of VENCorp's forecast opex.

Under cl. 9.8.4 of the derogation the AER must apply parts A-H of chapter 6A in determining transmission service revenues in respect of the Victorian transmission network. The application of chapter 6A is subject to the modifications set out in cl. 9.8.4B to cl. 9.8.4F of the derogation.[39] One of these modifications is that every reference in cl. 6A.6.6, which sets out the requirements for a TNSP's proposal and the AER's assessment of forecast operating expenditure is to be read as a reference to VENCorp.

In addition, in determining VENCorp's maximum allowed aggregate revenue (MAAR), the AER must apply the following principles:

[37] NER cl. 9.3.2(a)(1)(i)
[38] NER cl. 9.3.1(2)
[39] NER cl. 9.8.4

- The amount of VENCorp's MAAR must not exceed VENCorp's statutory electricity transmission-related costs, and
- VENCorp's MAAR must be determined on a full cost recovery but no operating surplus basis.

The AER has applied these principles in determining each component of VENCorp's MAAR, including forecast operating and planning expenditure.

2.2.1 Opex objectives

Clause 6A.6.6(a) provides that a TNSP must include in its revenue proposal a forecast of the total opex for the regulatory control period that the TNSP will require in order to achieve four prescribed objectives ("the opex objectives"), which are to:

1) meet the expected demand for prescribed transmission services over that period;
2) comply with all applicable regulatory obligations associated with the provision of prescribed transmission services;
3) maintain the quality, reliability and security of supply of prescribed transmission services; and
4) maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

Despite the derogations in chapter 9, each of these objectives appear to have at least some relevance to VENCorp. The references to "prescribed transmission services" are to be read as references to services in respect of which VENCorp may determine shared transmission network use charges. However, subject to this modification, each of these objectives would appear to be applicable to VENCorp's opex. This is especially true of clause 6A.6.6(a)(2), since all of VENCorp's activities as a TNSP would appear to be undertaken pursuant to regulatory obligations.

2.2.2 Opex criteria and factors

Under cl. 6A.6.6(b) of the NER, the AER must accept the forecast opex included in a revenue proposal if the AER is satisfied that the total forecast opex for the regulatory period reasonably reflects the operating expenditure criteria ("the opex criteria"), which are:

1) the efficient costs of achieving the operating expenditure objectives
2) the costs that a prudent operator in the circumstances of the relevant TNSP would require to achieve the operating expenditure objectives, and
3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

In making this assessment, the AER must have regard to the following factors ("the opex factors"), which are listed in cl. 6A.6.6(e) of the NER:

1) the information included in or accompanying the Revenue Proposal
2) submissions received in the course of consulting on the Revenue Proposal

3) such analysis as is undertaken by or for the AER and is published prior to or as part of the draft decision of the AER on the Revenue Proposal under rule 6A.12 or the final decision of the AER on the Revenue Proposal under rule 6A.13 (as the case may be)

4) benchmark operating expenditure that would be incurred by an efficient Transmission Network Service Provider over the regulatory control period

5) the actual and expected operating expenditure of the Transmission Network Service Provider during any preceding regulatory control periods

6) the relative prices of operating and capital inputs

7) the substitution possibilities between operating and capital expenditure

8) whether the total labour costs included in the capital and operating expenditure forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period

9) the extent to which the forecast of required operating expenditure of the Transmission Network Service Provider is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms, and

10) whether the forecast of required operating expenditure includes amounts relating to a project that should more appropriately be included as a contingent project under cl. 6A.8.1(b).

Clause 6A.6.6 states if the AER is not satisfied that a TNSP's forecast opex reasonably reflects the operating expenditure criteria then the AER must not accept the forecast opex in a revenue proposal.

If the AER does not accept the total forecast opex proposed by a TNSP, cl. 6A.14.1(3)(ii) of the NER requires the AER to include in its draft decision:

> …an estimate of the total of the Transmission Network Service Provider's required operating expenditure for the regulatory control period that the AER is satisfied reasonably reflects the operating expenditure criteria, taking into account the operating expenditure factors.

Each of the operating expenditure criteria would appear to have at least some relevance to VENCorp. For example, if VENCorp's opex will be incurred in complying with regulatory obligations, it would be appropriate for the AER to review whether the opex that is forecast by VENCorp reasonably reflects the efficient and prudent costs of doing so and a realistic expectation of demand forecasts and cost inputs.

Not all of the factors, set out in cl. 6A.6.6(e) appear to be relevant to VENCorp's revenue determination. In particular, the AER considers that the following factors have no application to VENCorp:

- the relative prices of operating and capital inputs (cl. 6A.6.6(e)(6))
- the substitution possibilities between opex and capex (cl. 6A.6.6(e)(7))

- whether the total labour costs included in VENCorp's opex forecast are consistent with the incentives provided by the AER's service target performance incentive scheme (cl. 6A.6.6(e)(8)), or
- whether the opex forecast includes amounts relating to a project that should more appropriately be included as a contingent project (cl. 6A.6.6(e)(10)).

The other factors have been considered by the AER to the extent they bear upon VENCorp's opex forecast and having regard to the special circumstances under which VENCorp operates.

2.3 VENCorp's proposal

VENCorp proposes an opex forecast of $44m (nominal) over the forthcoming six year regulatory period. Labour costs constitute the largest component of VENCorp's opex forecasts, or 45% of total opex – followed by service department allocations (19%), consultancies and contractors (17%) and computing and communications (10%). VENCorp's opex forecasts are set out in the table below.

Table 2.1 VENCorp proposal – Opex (nominal $m)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
Labour	2.94	3.07	3.18	3.36	3.48	3.62	19.65
Contracted services	0.22	0.24	0.24	0.25	0.25	0.26	1.46
Computing & communications	0.63	0.68	0.69	0.71	0.73	0.75	4.19
Consultancies & contractors	1.12	1.17	1.19	1.25	1.28	1.32	7.33
Vehicles & travel	0.06	0.06	0.06	0.06	0.07	0.07	0.38
Occupancy	0.18	0.18	0.19	0.20	0.20	0.21	1.16
Administrative costs	0.11	0.12	0.12	0.12	0.13	0.13	0.73
Depreciation & amortisation	0.12	0.13	0.13	0.13	0.13	0.14	0.78
Service department allocations	1.30	1.34	1.36	1.40	1.44	1.48	8.32
Total	**6.69**	**6.98**	**7.17**	**7.47**	**7.71**	**7.98**	**44.00**

Source: VENCorp[40]

VENCorp has forecast its future opex using its 2006-07 budgeted expenditure for each category as a base year. From this base year expenditure, VENCorp has projected its labour forecasts based on an annual escalator of 4.5% (nominal), and projected its non-labour forecasts based on an annual escalator of 3.0% (nominal). VENCorp claims that its labour cost escalator is in line with VENCorp's Enterprise

[40] VENCorp, *VENCorp Electricity Revenue Cap Proposal – 1 July 2008 to 30 June 2014*, p. 35.

Bargaining Agreement, estimated performance based increases, and the AER's own views based on the Access Economics report commissioned by the AER for the recent Powerlink revenue decision. VENCorp states that its non-labour cost escalator is within the RBA's target inflation band.[41]

VENCorp states that its costs remain relatively stable with only two major variables:

- Labour costs – which vary due to an annual revaluation of VENCorp's defined benefit superannuation obligation, required under International Financial Reporting Standards (IFRS), and
- Consultancy costs – which vary depending on what "one-off" projects it undertakes year to year.[42]

On cost allocation, VENCorp states that each of the categories in the above table relates directly to expenditure VENCorp expects to incur in carrying out its statutory electricity related functions. The expenditure in each category is either only incurred by the electricity segment, or is allocated to the electricity segment based on the number of full time equivalent (FTE) staff in the electricity segment (e.g. computing costs). The exception to this is "service department allocations", which relates to expenditure (e.g. legal, human relations) that is not directly incurred by any particular segment (i.e. electricity, gas, contestability, corporate). This expenditure is pooled, and then allocated based on the number FTE staff in the electricity segment, or the number of hours worked in the electricity segment as a percentage of total organisational hours, depending on the type of expenditure.[43]

2.4 Submissions

Transend

Transend comments on VENCorp's argument that the Victorian electricity transmission arrangements and VENCorp's governance arrangements should provide the AER and other stakeholders with a considerable degree of comfort that the operating costs incurred by VENCorp in undertaking its network service provision, network planning and related functions are efficient. Transend notes that:

> …economic theory and business practice strongly suggest that the profit motive within a CPI-X regulatory framework provides a very powerful incentive to drive efficiency improvements. It is highly questionable whether the improvements in efficiency that have been observed across a number of regulated sectors both nationally and internationally could have been achieved by adopting a not-for-profit governance framework.[44]

Energy Users Coalition of Victoria

The Energy Users Coalition of Victoria (EUCV) comments that, whilst VENCorp's direct operational costs only constitute a small part of its proposal and these costs

[41] ibid., p. 36
[42] ibid., p. 35
[43] ibid., p. 64
[44] Transend, *Letter on VENCorp and SP AusNet Revenue Proposals*, 13 June 2007, pp. 1-2.

have been forecast from current levels, it is essential that the current costs can be demonstrated to be prudent and efficient.[45]

2.5 Consultant's review

In order to analyse VENCorp's forecast opex, PB carried out a review of VENCorp's historical expenditure patterns and reviewed VENCorp's 2006-07 year-to-date opex spend, as at February 2007, for five of the most significant opex cost categories. PB also reviewed VENCorp's cost allocation methodology.

For comparison purposes, PB converted VENCorp's opex allowance for the current regulatory period, and VENCorp's actual/budgeted opex over the same period, into 2007-08 dollars.

Table 2.2 PB analysis – Historical opex (2007-08 $m)

	2003-04	2004-05	2005-06	2006-07	2007-08
Forecast	6.4	6.5	7.0	7.0	7.2
Actual / budgeted[46]	5.3	5.2	3.6	6.3	6.3
Underspend	1.1	1.3	3.4	0.7	0.9

Source: PB[47]

As shown in the above table, VENCorp's actual opex for the first three years of the current regulatory period was significantly less than its allowance, particularly in 2005-06 where VENCorp's actual opex was 48%, or $3.4m ($2007-08), less than its allowance. VENCorp's budgeted opex for the final two years of the current regulatory period is also less than its allowance, though greater than its actual opex from preceding years.

VENCorp indicated to PB that the significant under expenditure in 2005-06 was primarily due to two "one off" issues: an inability to fill labour vacancies ($1.7m underspend, nominal); and factors related to VENCorp's defined benefit superannuation obligation ($1.3m positive adjustment and holiday, nominal). These factors contributed to $1.9m ($2007-08) of VENCorp's 2005-06 underspend. For comparison purposes PB recommends revising VENCorp's actual 2005-06 expenditure to account for these one off issues resulting in an adjusted actual 2005-06 expenditure of $5.54m ($2007-08).

After examining VENCorp's 2006-07 year-to-date expenditure (as at February 2007), PB concluded that VENCorp's year-to-date actual expenditure was $0.72m (nominal) under budget, and calculated a probable outcome for full-year actual expenditure of

[45] EUCV, *SP AusNet and VENCorp Applications – A Response by the Energy Users Coalition of Victoria*, June 2007, p. 13.
[46] Years 2003-04, 2004-05 and 2005-06 are actual expenditure. Years 2006-07 and 2007-08 are budgeted expenditure.
[47] PB Strategic Consulting, *VENCorp revenue reset – An independent review – Prepared for AER, 8 October 2007*, p. 100.

$5.59m (nominal), assuming the level of under expenditure remained constant for the remainder of the year. Accordingly for comparison purposes PB recommend revising VENCorp's budgeted 2006-07 expenditure to an expected actual expenditure of $5.59m (nominal).

These adjustments are reflected in the table below. After making the adjustments, PB calculated that VENCorp's actual opex, as adjusted, increased annually by $0.08m ($2007-08), on average, between 2003-04 to 2006-07.

Table 2.3 PB analysis – Adjusted historical opex ($m 2007-08)

	2003-04	**2004-05**	**2005-06**	**2006-07**	**2007-08**
Forecast	6.38	6.50	6.97	6.97	7.21
Actual / budgeted (PB adjusted)[48]	5.26	5.24	5.54	5.59	6.30
Underspend (PB adjusted)	1.12	1.26	1.43	1.38	0.91

Source: PB[49]

As PB's review of VENCorp's 2006-07 year-to-date expenditure indicated instances of over budgeting, which was also consistent with that found in previous years, PB concluded that VENCorp's 2006-07 budgeted expenditure was "not an efficient starting point on which to base forecast future operating and planning expenditures".[50]

Adopting the 2006-07 budgeted expenditure as the base year would effectively lead to a step change in costs from historical levels. On this PB states that:

> PB has not seen any evidence to support a step change in operating and planning expenditure for the next regulatory period. The VENCorp Proposal and our discussions with VENCorp support a business as usual approach to forecasting future operating and planning expenditures. Hence PB is of the view that the current small real annual increase in operational and planning expenditures evident in the current regulatory period are likely to continue throughout the next regulatory period.[51]

Accordingly PB recommends that its estimate of VENCorp's probable 2006-07 actual expenditure of $5.59m ($2007-08) be adopted as the base year, and that this be increased by $0.08m ($2007-08) annually to project VENCorp's forecast opex for the forthcoming regulatory period. This recommendation results in a total reduction from VENCorp's opex proposal of $3.88m ($2007-08), or $4.31m (nominal).[52]

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[48] Years 2003-04, 2004-05 and 2005-06 are actual expenditure. Years 2006-07 is expected actual expenditure. Year 2007-08 is budgeted expenditure.
[49] PB Strategic Consulting, *op cit,* p. 103.
[50] ibid., p. 107
[51] ibid., p. 106
[52] Conversion of PB's recommendation from 2007-08 dollars to nominal dollars assumes forecast inflation of 3%.

Table 2.4 PB recommendation – Opex (nominal $m)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
VENCorp's proposal	6.69	6.98	7.17	7.47	7.71	7.98	44.00
PB's adjustment	-0.77	-0.79	-0.71	-0.73	-0.67	-0.64	-4.31
PB's recommendation	**5.92**	**6.19**	**6.46**	**6.74**	**7.04**	**7.34**	**39.69**

Source: VENCorp[53]

PB considers that VENCorp's allocation of costs to its business segments provides an appropriate allocation of costs to the regulated electricity segment and that the costs attributable to the regulated electricity segment are allocated to the appropriate accounts.[54]

2.6 Issues and AER's considerations

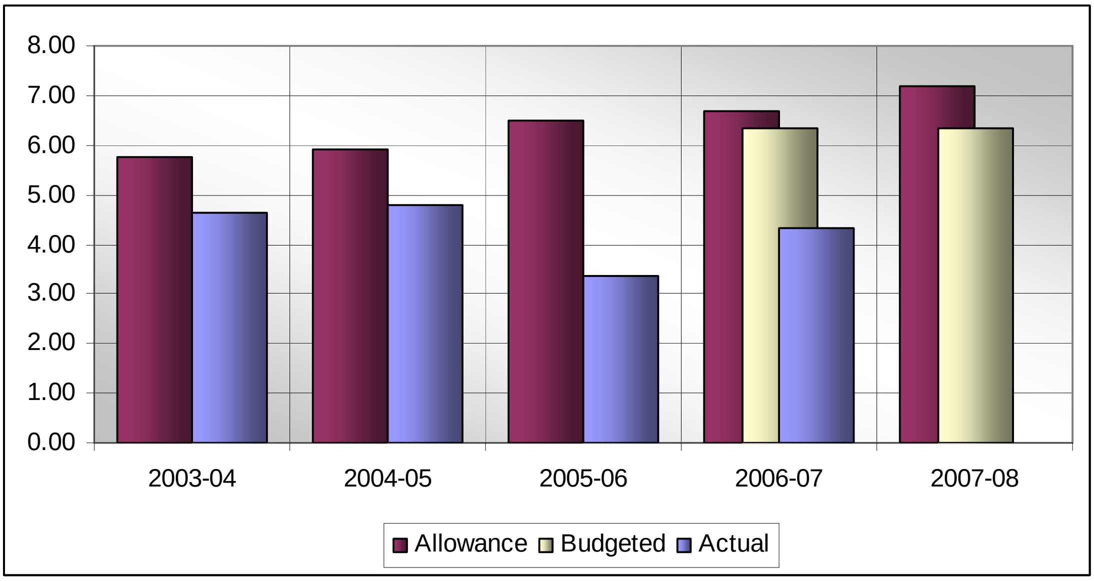
As required by cl. 6A.6.6(e)(5) of the NER, the AER has examined VENCorp's actual and expected opex from the current regulatory period. This examination has been informed by PB's analysis of actual and budgeted expenditure in the current regulatory period. The AER considers that while the difficulties in filling staff vacancies and the defined benefit superannuation obligation adjustment account for some of the difference between VENCorp's actual and forecast opex in the current regulatory period, these two factors do not adequately explain all of the underspend in each of the opex line items over the current regulatory period. Furthermore, PB has been unable to find any reason for the continual under expenditure in the current regulatory period. The AER agrees with PB's conclusion that the difference between VENCorp's actual and forecast opex in the current regulatory control period suggests a historical pattern of under expenditure in opex compared to annual forecasts, and that this is likely to continue if VENCorp's proposed opex forecasts are approved.

2.6.1 Base year

The AER agrees with PB's recommendation that VENCorp's 2006-07 budgeted expenditure is not an efficient starting point from which to base forecast future operating and planning expenditures. The issue, however, is not so much the use of 2006-07 expenditure, but rather the use of 2006-07 budgeted, instead of 2006-07 actual expenditure.

[53] VENCorp, *op cit*, p. 35
[54] PB Strategic Consulting , *op cit*, p. 102

Figure 2.1 VENCorp's allowed, budgeted and actual opex during the current regulatory period (nominal $m)[55]



Source: ACCC, VENCorp[56]

As can be seen in the figure above, VENCorp's budgeted 2006-07 expenditure as proposed in its February 2007 proposal ($6.33m, nominal) was significantly above its actual 2006-07 expenditure ($4.35m, nominal), by an amount of $1.98m (nominal). VENCorp's budgeted 2006-07 expenditure was also significantly above its actual expenditure from previous years. Adopting VENCorp's 2006-07 budgeted expenditure as the base from which to forecast its future opex requirements results in an upwards step change from VENCorp's current actual opex costs. The AER agrees with PB that VENCorp has not provided any evidence justifying such a step change. In fact, statements by VENCorp in its proposal that "the majority of VENCorp's costs will remain relatively stable" and "VENCorp's operating and planning expenditure is expected to continue along its current trend" do not support a step change either.

Accordingly PB recommended adopting VENCorp's actual 2006-07 expenditure as the base year. As this was not known at the time of PB's review, PB had to estimate this amount. The AER notes that VENCorp's actual 2006-07 full year expenditure is now available.

The AER has examined the reasonableness of adopting VENCorp's actual 2006-07 expenditure as the base year, paying particular attention to the two categories that VENCorp states are its only two major opex variables – labour costs (due to the defined benefit superannuation adjustment) and consultancy costs.

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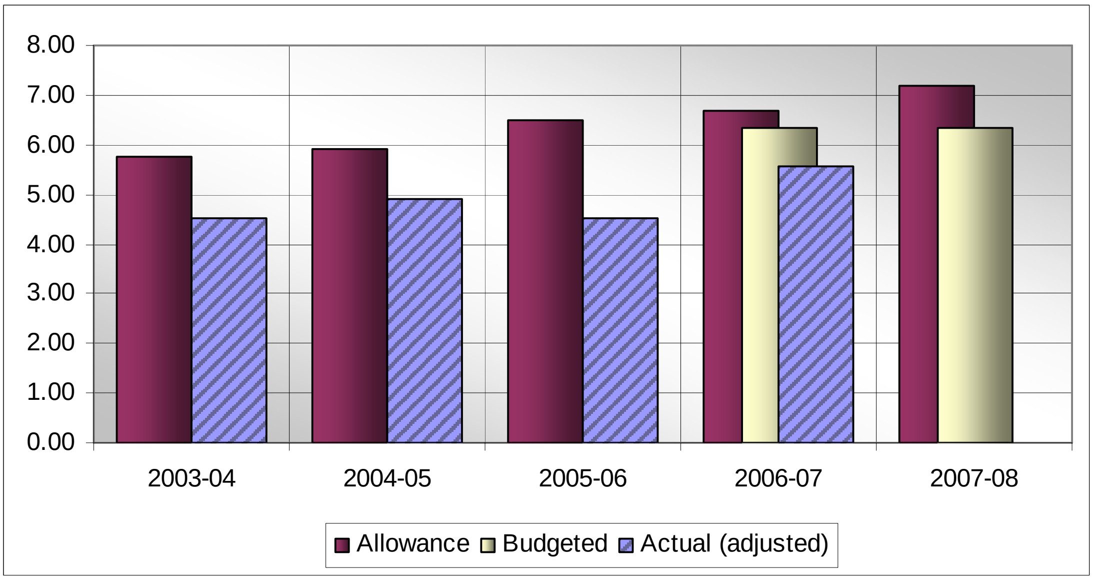
[55] VENCorp misrepresented its opex allowance for the current regulatory period in its proposal (table 8.2), stating that the table displayed its opex allowance in nominal terms when the figures in the table showed VENCorp's opex allowance in real 2001-02 dollars. VENCorp conceded the error when questioned.

[56] ACCC, *Decision – Victorian Transmission Network Revenue Caps 2003-2008*, 11 December 2008. ACCC, *Letter to VENCorp – Application for adjustment of VENCorp's maximum allowable aggregate revenue*, 3 May 2004. VENCorp, *VENCorp Electricity Revenue Cap Proposal – 1 July 2008 to 30 June 2014*. VENCorp – *Year to date statement of financial performance*, June 2007.

Under International Financial Reporting Standards (IFRS), VENCorp is required to recognise defined benefit superannuation liabilities or surpluses of defined benefit plans, and must recognise the effect of changes in the defined benefit liability or surplus in its operating statement. Accordingly, the adjustment is reflected in VENCorp's actual expenditure as reported. However, this adjustment is a non-cash expense and bears no effect on VENCorp's future opex requirements. Accordingly the AER considers it appropriate to exclude the adjustment from VENCorp's actual 2006-07 expenditure to develop a prudent base year expenditure.[57] To display VENCorp's underlying actual opex, the defined benefit adjustment has been removed from VENCorp's actual opex in each year in the figure below.

Figure 2.2 VENCorp's allowed, budgeted and adjusted actual opex during the current regulatory period (nominal $m)



Sources: VENCorp, AER analysis[58]

As shown in the table above, VENCorp's adjusted actual 2006-07 expenditure ($5.57m, nominal) is still less than the budgeted 2006-07 expenditure. However, as the adjusted actual 2006-07 expenditure is greater than adjusted actuals from previous years, this suggests that adopting the adjusted actual 2006-07 expenditure is a conservative assumption, and more likely to overstate than understate the efficient level from which to forecast VENCorp's future opex requirements. The AER notes that part of this higher 2006-07 spend is explained by the higher spend on "consultancies and contractors" in 2006-07, which was $0.61m (nominal), or 110%, greater than the average spend on consultancies and contractors between 2003-04 and

[57] The AER notes that VENCorp's "depreciation and amortisation" category is also a non-cash expense, and that for the purposes of regulatory revenue setting it would be preferable if the underlying costs were recognised on a cash basis as they are incurred. However due to the relatively minor size of this category (e.g. $0.08m, nominal, actual expenditure in 2006-07) the AER considers this issue immaterial.

[58] ACCC, *Decision – Victorian Transmission Network Revenue Caps 2003-2008*, 11 December 2008. ACCC, *Letter to VENCorp – Application for adjustment of VENCorp's maximum allowable aggregate revenue*, 3 May 2004. VENCorp, *VENCorp Electricity Revenue Cap Proposal – 1 July 2008 to 30 June 2014*. VENCorp – *Year to date statement of financial performance*, June 2007. VENCorp, *Email to AER – RE: Table 8.2 VENCorp Proposal*, 10 October 2007.

2005-06. As VENCorp states that expenditure on consultancies varies year to year, adopting a base year which has a relatively high spend on consultancies is is again more likely to overstate than understate VENCorp's future consultancy requirements.

The AER considers $5.57m (nominal), being VENCorp's actual 2006-07 expenditure, adjusted to remove the defined benefit adjustment, is a prudent, if conservative, base from which to forecast VENCorp's future opex requirements.

2.6.2 Cost escalators

As noted above, VENCorp proposes an annual labour cost escalator of 4.5% (nominal) and an annual non-labour cost escalator of 3.0% (nominal).

In the recent SP AusNet draft decision the AER accepted SP AusNet's labour cost escalator which was based on BIS Shrapnel's 5.70% (nominal) annual wage growth forecast for the electricity, gas and water sector in Australia over 2008-13. For the same review, the AER's independent consultants, Econtech and PB, recommended wage growth forecasts of 6.38% (nominal) and 5.13% (nominal), respectively. Based on this analysis, the AER considers VENCorp's proposed 4.5% labour cost escalator does not overstate the costs a prudent operator in the circumstances of VENCorp would require to achieve the opex objectives.

As VENCorp has a public sector workforce and does not employ the specialist outdoor staff that other TNSPs employ, the AER considers it reasonable to expect that VENCorp would not experience wage growth of the same magnitude as that forecast for the electricity, gas and water sector more generally. The AER also notes that VENCorp's labour cost escalator is based on its current enterprise bargaining agreement, which whilst it expires in March 2008, the AER considers a reasonable basis from which to forecast wage growth over the near term.

The AER also considers VENCorp's 3% (nominal) non-labour cost escalator reasonably reflects the efficient costs of achieving the opex objectives. The AER considers that these cost escalators are preferable to the cost escalator proposed by PB (an annual increase of $0.08m ($2007-08)) as they are better tailored to the likely increases in labour and non-labour costs.

2.6.3 Cost allocation

Based on the information in VENCorp's proposal on its cost allocation methodology and PB's assessment, the AER is satisfied that VENCorp's cost allocation methodology results in VENCorp's stated opex costs reflecting only those costs relating to VENCorp's statutory electricity transmission-related costs.
The AER also considers that VENCorp's cost allocation methodology complies with the requirements of First Proposed Cost Allocation Guidelines.
The AER considers that VENCorp's cost allocation methodology is an acceptable methodology for apportioning costs across VENCorp's different business functions. The allocation of costs has been undertaken according to the substance of the transaction rather than its legal form, costs directly attributable have been allocated accordingly, costs that are not directly attributable have been apportioned on a causation basis, and costs have not been allocated more than once.

2.7 AER’s conclusion

The AER has considered VENCorp’s total opex forecast of $44m (nominal) and, for the reasons outlined in this chapter, is not satisfied that the opex forecasts proposed by VENCorp reasonably reflect:

- the efficient costs of achieving the opex objectives
- the costs that a prudent operator in the circumstances of VENCorp would require to achieve the opex objectives, and
- a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.

In the context of the requirement that the amount of VENCorp’s MAAR not exceed its statutory electricity transmission-related costs, and must be determined on a full cost recovery but no operating surplus basis, the AER has given particular attention to the requirement that VENCorp’s forecast reasonably reflect a realistic expectation of the costs that VENCorp will require to fulfil its statutory electricity transmission-related functions in the forthcoming regulatory period.

In forming this position the AER has had regard to the applicable opex factors set out in cl. 6A.6.6(e) of the NER, and in particular:

- the information included in and accompanying VENCorp’s revenue proposal
- submissions from Transend and the EUCV received in the course of consulting on the revenue proposal
- analysis undertaken by the AER (as outlined above) and for the AER by its independent consultant PB (the report from whom has been published, and should be read in conjunction with this draft decision), and
- the actual and expected opex of VENCorp during the current regulatory period.

Two other factors (cll. 6A.6.6(e)(4) and (9)) are, technically, applicable to VENCorp, but were found to have no relevance to this draft decision. The special circumstances under which VENCorp operates make it impossible to identify useful benchmarks against which to compare VENCorp’s opex forecast. The AER is not aware of any agreements between VENCorp and another person that do not reflect arm’s length terms, which could affect its opex forecast.

As the AER is not satisfied that VENCorp’s proposed forecast of $44m (nominal) reasonably reflect the opex criteria, the AER has not accepted the forecast opex in VENCorp’s revenue proposal.

The AER has substituted a required opex forecast of $39.37m ($2007-08) which the AER is satisfied reasonably reflects the opex criteria, taking into account the relevant opex factors. In making this adjustment the AER has:

- accepted VENCorp’s proposed base year of 2006-07. However the AER has substituted VENCorp’s budgeted 2006-07 expenditure with its actual 2006-07 expenditure, now that this is known. The AER has also made a positive adjustment to the actual 2006-07 expenditure to remove the effect of the defined benefit superannuation adjustment, which the AER considers is not relevant to VENCorp’s future opex requirements, and

- accepted VENCorp's proposed cost escalators of 4.5% (nominal) for labour and 3.0% (nominal) for non-labour costs.

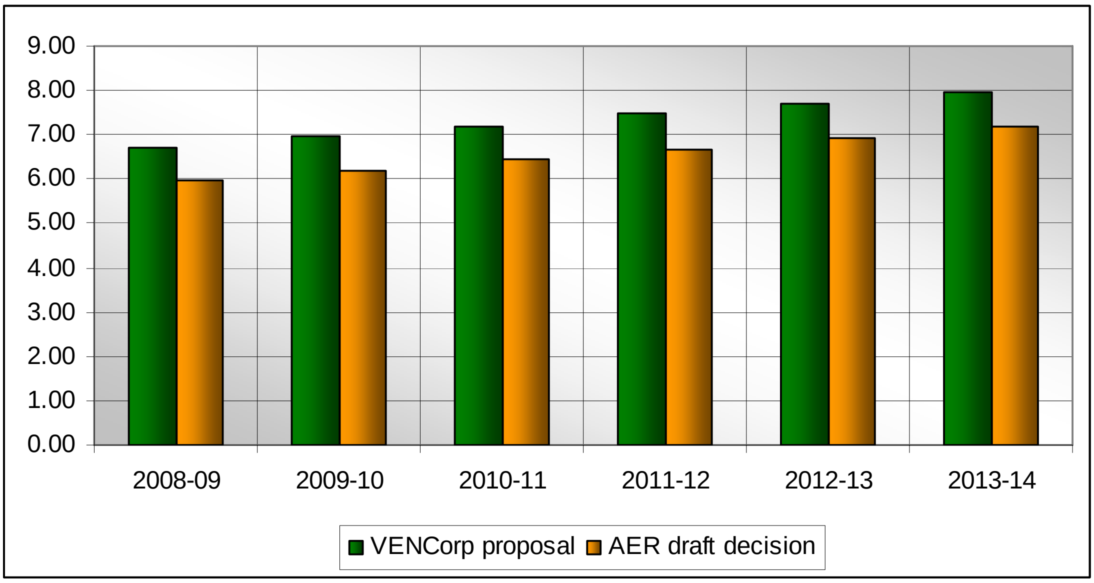
The AER is satisfied that VENCorp's cost allocation methodology allocates only statutory electricity transmission-related costs to VENCorp's electricity segment cost accounts. As these accounts have been used to project VENCorp's opex allowance the AER is satisfied the opex component of VENCorp's MAAR will not exceed VENCorp's statutory transmission-related opex costs. The AER is also satisfied that the opex allowance determined by the AER will result in the opex component of VENCorp's MAAR being set on a full cost recovery but no operating surplus basis.

Table 2.5 AER's draft decision – Opex (nominal $m)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
VENCorp's proposal	6.69	6.98	7.17	7.47	7.71	7.98	44.00
AER's adjustment	-0.70	-0.78	-0.74	-0.80	-0.80	-0.81	-4.63
AER's draft decision	**5.99**	**6.20**	**6.43**	**6.67**	**6.91**	**7.17**	**39.37**

Source: VENCorp[59], AER analysis

Figure 2.3 AER draft decision – Opex (nominal $m)



Source: VENCorp[60], AER analysis

59 VENCorp, *op cit*, p. 35
60 ibid.

3 Committed network augmentation and charges

3.1 Introduction

VENCorp is responsible for the planning, development and augmentation of the Victorian electricity transmission network.[61] Unlike other TNSPs, VENCorp does not own any transmission assets, and does not have a RAB. It fulfils its statutory responsibilities to augment the network by procuring bulk transmission services under contract from SP AusNet and other owners of Victorian electricity transmission assets.

Network augmentation expenditure is incurred by VENCorp in the form of charges payable by VENCorp to transmission asset owners for the provision of bulk transmission services provided under existing contracts won through a competitive tender process, or where otherwise directed by VENCorp in the current regulatory period. In VENCorp's revenue proposal and this draft decision these charges are referred to as committed augmentation charges. The total expenditure underlying those charges, which will be recovered over the life of the contract, is referred to as committed augmentation expenditure. In each regulatory period, it is the forecast committed augmentation charges payable in that period, and not the total value of the relevant contracts, that form one of the building blocks of VENCorp's MAAR.

This chapter considers VENCorp's forecast of committed augmentation charges for the forthcoming regulatory period. The AER has also reviewed VENCorp's committed augmentation expenditure and charges in order to inform its assessment of VENCorp's forecast planned augmentation expenditure and charges for the forthcoming regulatory period. This analysis is set out in chapter 4.

3.2 Regulatory requirements

Under cl. 9.8.4C(a) of the Victorian jurisdictional derogation, VENCorp's MAAR must be set to allow VENCorp to fully recover its statutory electricity transmission related costs, including charges payable under contracts entered into in the current regulatory period, and existing contracts from before that period.

The effect of this derogation is to permit VENCorp to recover, as part of its MAAR, the actual charges that will be paid under existing contracts. Accordingly, the capital expenditure criteria set out in cl. 6A.6.7(c) do not apply in their entirety to this part of VENCorp's revenue proposal. There is no scope for the AER to review the prudency or efficiency of committed augmentation expenditure, since VENCorp is entitled to recover all charges that will be paid under existing contracts. This means that cl. 6A.6.7(c)(1) and (2), while they are relevant to the AER's assessment of the forecast planned augmentation expenditure which underlies VENCorp's forecast planned augmentation charges that will be payable under contracts not yet entered into, have no application to this part of VENCorp's revenue proposal. The AER has

[61] NER cl. 9.3.2(a)(1)(i)(A).

not conducted an ex-post prudency assessment of VENCorp's augmentation expenditure in the current regulatory period as it has done for SP AusNet, and has no role in optimising expenditure incurred by VENCorp in the current period.

However, cl. 6A.6.7(c)(3) is applicable, to the extent that the AER must be satisfied that VENCorp's forecast committed augmentation expenditure reasonably reflects a realistic expectation of the charges that it will incur under its existing contracts in the coming regulatory period. This is ensure that the MAAR, which is set on the basis of that forecast, will not exceed VENCorp's statutory electricity transmission related costs and is set on a full cost recovery but no operating surplus basis as required by the derogation.

The charges that will actually be payable as committed augmentation charges in the forthcoming regulatory period are those charges payable under contracts entered into in the current and preceding periods. These figures cannot simply be extracted from the contracts, most of which have long lives that span more than one regulatory period. The profile of expenditure over the life of a contract may change. Project specifications may be subject to variation from the specification set out in the original contract. It is necessary to produce a reliable forecast of the amounts that will be payable by VENCorp, under these contracts, over the coming regulatory period.

3.3 VENCorp's proposal

VENCorp's revenue proposal compares its actual network augmentation expenditure over the current regulatory period with the forecast approved in the ACCC's 2002 decision. It states that its actual expenditure is forecast to be \$140.6m, around \$20m less[62] than forecast at the time of the current revenue determination.[63]

Clause 9.8.4C(g2) enables VENCorp to apply for a MAAR adjustment within a regulatory period if it exceeds, or anticipates that it will exceed, the MAAR set by the AER at the time of the revenue determination. During the current regulatory period, VENCorp requested an additional \$15m in augmentation expenses resulting from the conversion of the Murraylink interconnector from an unregulated asset to a regulated asset in May 2004. The ACCC approved this adjustment to its 2002 decision in May 2004.[64] This MAAR adjustment increased VENCorp's forecast network augmentation expenditure to \$170m for the current regulatory period. This means that VENCorp's estimated actual expenditure is in fact nearly \$30m less than the total allowance approved for the current regulatory period when the revised allowance approved in 2004 to accommodate Murraylink conversion is taken into account.

VENCorp claims the key reason for the variance between the forecast and actual network augmentation expenditure was the deferral of the installation of the fourth Dederang 300/200kV transformer, an allowance for which is now sought in VENCorp's forecast planned augmentation charges for the forthcoming regulatory

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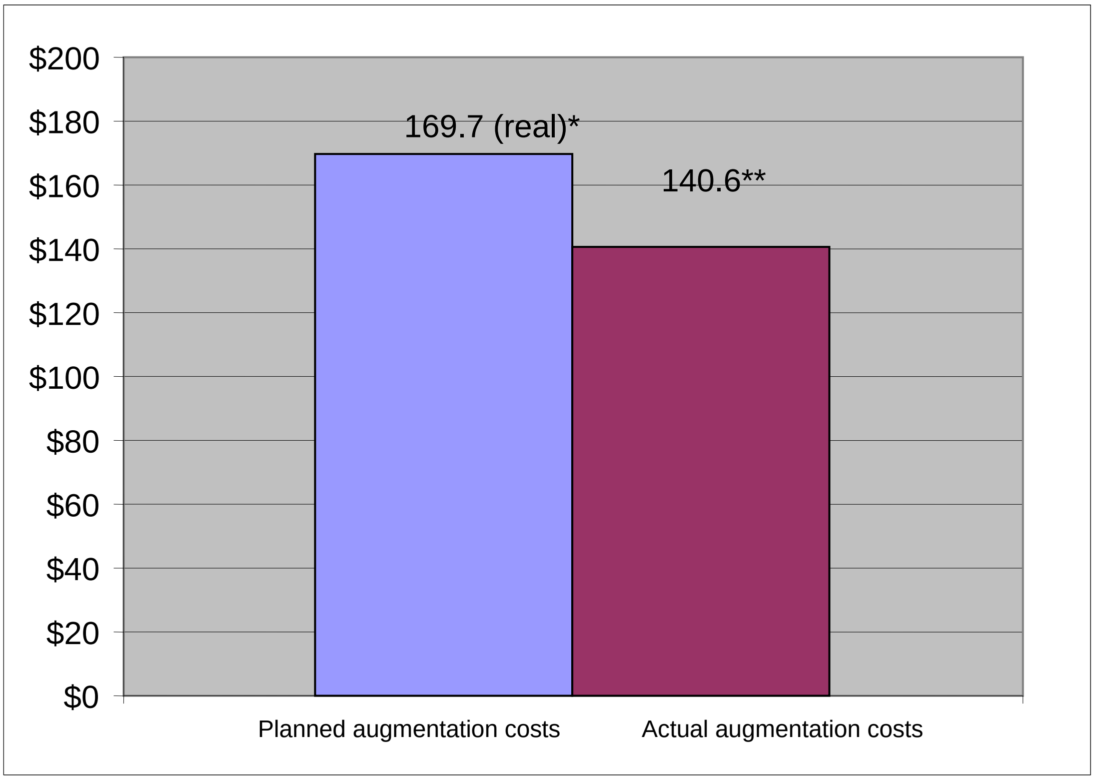
[63] VENCorp, *VENCorp Electricity Revenue Cap Proposal – 1 July 2008 to 30 June 2014*, p. 24.
[64] Letter ACCC to VENCorp, *Application for adjustment to VENCorp's maximum allowable aggregate revenue*, 3 May 2004 (available on the AER's website at http://www.aer.gov.au/content/index.phtml/itemId/661077/fromItemId/709572

period. VENCorp also states that the requirement for reactive support works within the current regulatory period was displaced by several other projects.[65]

Balancing the deferral and displacement of these elements of the approved forecast was the installation of a second transformer at Moorabool, which was not forecast at the time the ACCC's 2002 decision was made.

VENCorp has confidentially provided the AER with a year on year breakdown of its committed network augmentation expenditure in the current regulatory period. A comparison of VENCorp's forecast and actual network augmentation aggregated over the current regulatory period is shown below in figure 3.1.

Figure 3.1 A comparison of forecast augmentation expenditure with actual augmentation expenditure.



*Column1 represents ACCC 2002 decision as amended by 2004 decision on Murraylink conversion
**Column 2 includes a forecast expenditure from 1 March 2007 to 30 June 2008

VENCorp's proposal provides a forecast of the committed augmentation charges VENCorp expects to be payable in the forthcoming regulatory period. VENCorp states that this forecast is based on the information set out in sections 6.2 and 6.3 of its revenue proposal.

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[65] VENCorp, *op cit*, p. 23

Table 3.1 Committed augmentation charges for the forthcoming period ($m, nominal excluding GST)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
Committed augmentation charges	22.9	23.6	24.3	25.0	25.7	26.5	148.00

Source: VENCorp revenue proposal p. 25

3.4 Submissions

The EUCV comments on the recovery of costs through VENCorp's committed augmentation charges. The EUCV notes that:

> VENCorp has an approach that allows for these augmentations to be recovered over a shorter term than the economic life of the asset. This means that at some point, the assets will have returned the full value of depreciation, before the assets themselves are determined to have completed their true economic or physical life.[66]

The EUCV considers that this approach impacts users in two ways. Firstly it states that current users will incur a greater cost, as charges are calculated with regard to an accelerated rate of depreciation. Secondly, the EUCV considers that unless VENCorp specifically agrees within the contract for the provision of assets to be for operating costs only at the end of the depreciation period, future users will be levied a cost for using these sunk (but still monopoly) assets which have already been fully depreciated. [67]

3.5 Consultant's review

The AER engaged PB to conduct a review of VENCorp's committed augmentation expenditure in order to better inform its assessment of VENCorp's planned augmentation proposal.

The purpose of this review was not to inform the AER's decision on VENCorp's forecast committed augmentation expenditure (since VENCorp is entitled to recover committed augmentation expenditure under its MAAR irrespective of whether it is considered to be prudent or efficient) but rather to help inform the AER's assessment of VENCorp's forecast *planned* augmentation expenditure for the coming regulatory period. Accordingly, the results of this review are discussed in chapter 4.

3.6 Issues and AER's considerations

Sections 6.2 and 6.3 of VENCorp's revenue proposal describe the augmentation projects that the ACCC approved when setting VENCorp's revenue cap in 2002 and the augmentation projects committed to during the current period. However,

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[66] Victorian Electricity Transmission Revenue Reset – *A response by Energy Users Coalition of Victoria – June 2007* p. 13
[67] ibid., p. 14

VENCorp has only set out the value of each of these projects (ie. the estimated value of each of these contracts over the contract life), and not the forecast charges payable under these contracts over the coming regulatory period.

As noted in section 3.2 of this chapter, the scope of the AER's review of committed augmentation expenditure is limited. The AER has approached VENCorp's committed augmentation expenditure on the basis that it must be satisfied only that VENCorp's forecast reasonably reflects a realistic expectation of the charges that will be payable under existing contracts in the coming period.

VENCorp has explained that its forecast committed augmentation charges are derived from its budgeted network payments for 2008-09, the first year of the forthcoming regulatory period.

At the request of the AER, VENCorp provided a spreadsheet presenting its network payments budget for the 2008-09 financial year.[68] The spreadsheet assumes that there are no changes in the WACC calculations, which VENCorp states SP AusNet is required to provide to VENCorp at the time of any change following SP AusNet's regulatory reset.[69] From its review of a limited sample of contracts, the AER considers this to be a reasonable assumption for the purposes of a forecast of the committed augmentation charges that will be payable in the first year of the coming regulatory period.[70]

In the course of reviewing and verifying the calculations in the spreadsheet, the AER identified a number of errors in the form of inappropriate inclusion and exclusion of contracts in VENCorp's calculations. These errors have been confirmed with VENCorp.[71] The correct calculation of network payments in VENCorp's forecast should in fact be $19.35m, and not $22.9m as indicated in its revenue proposal.

For the remaining years of the forthcoming regulatory period, VENCorp states that it has inflated its 2008-09 forecast by an assumed CPI of 3% per annum.[72]

The AER does not consider that VENCorp's 3% escalator can be justified solely by reference to inflation. This is because such an escalator ignores the downward trend in the real price of the contract charges over the life of a contract that results from the application of the WACC to a depreciating asset base, which forms a major component of the overall charges.

However, the AER's review of supporting information provided by VENCorp does indicate that, after VENCorp enters into contracts, many contracts are subsequently varied, and that most variations result in an increase in the overall contract price. When the real downward trend in the "return on" component of the contract charges is considered in the context of the uncertainty surrounding potential contract variations within the regulatory period, and inflation within the period, it is not unreasonable to expect that, within the forthcoming regulatory period, committed augmentation

[68] VEN_DOCS-#225093-v1-Network_Payments_Budget_2008_09.XLS
[69] Email VENCorp to AER, 16 October 2007
[70] Email VENCorp to AER, 10 October 2007
[71] Email VENCorp to AER, 22 October 2007; Teleconference AER to VENCorp 23 October 2007
[72] Email VENCorp to AER, 17 October 2007

charges will in fact increase over time. While not endorsing VENCorp's argument that charges should be inflated by CPI, the AER considers on the balance of the information provided that a forecast based on an assumed increase of 3% per annum is not unrealistic.

When applied to the corrected forecast of $19.35m, this 3% per annum increase produces a total forecast of committed augmentation charges for the forthcoming regulatory period that is $22.84m lower than that in VENCorp's revenue proposal.

In light of this overstatement, the AER is not satisfied that VENCorp's forecast committed augmentation charges reasonably reflect a realistic expectation of the charges that will be payable under existing contracts in the coming period. Accordingly, in the context of the requirement in cl. 9.8.4C(a)(2) that VENCorp's MAAR be set on a full cost recovery basis, the AER has decided not to approve VENCorp's forecast of its committed augmentation expenditure for the coming regulatory period and to instead approve a lower amount which is based on a corrected forecast as noted above.

3.7 AER's conclusion

Having reached the conclusion that it can not, with regard to the criterion set out on cl. 6A.6.7(c)(3) and the information included in and accompanying VENCorp's revenue proposal, be satisfied that VENCorp's forecast committed augmentation charges reasonably reflects a realistic expectation of the charges that it will incur under its existing contracts in the coming regulatory period, the AER must use a substitute forecast.

The AER recognises that VENCorp will, in the forthcoming regulatory period, be required to pay charges under existing contracts entered into in and prior to the current regulatory period. In determining a forecast of committed augmentation charges, the AER has had reference to the principles set out in cl. 9.8.4C(a), which require that VENCorp's MAAR, and implicitly therefore the inputs to that MAAR, be determined on a full cost recovery no operating surplus basis, and in an amount that does not exceed VENCorp's statutory electricity transmission related costs.

For the purposes of this draft decision, the AER has substituted its own forecast committed augmentation charges, which have been derived from the estimate of charges payable in 2008-09, escalated by 3% per annum in each subsequent year of the regulatory period**.**

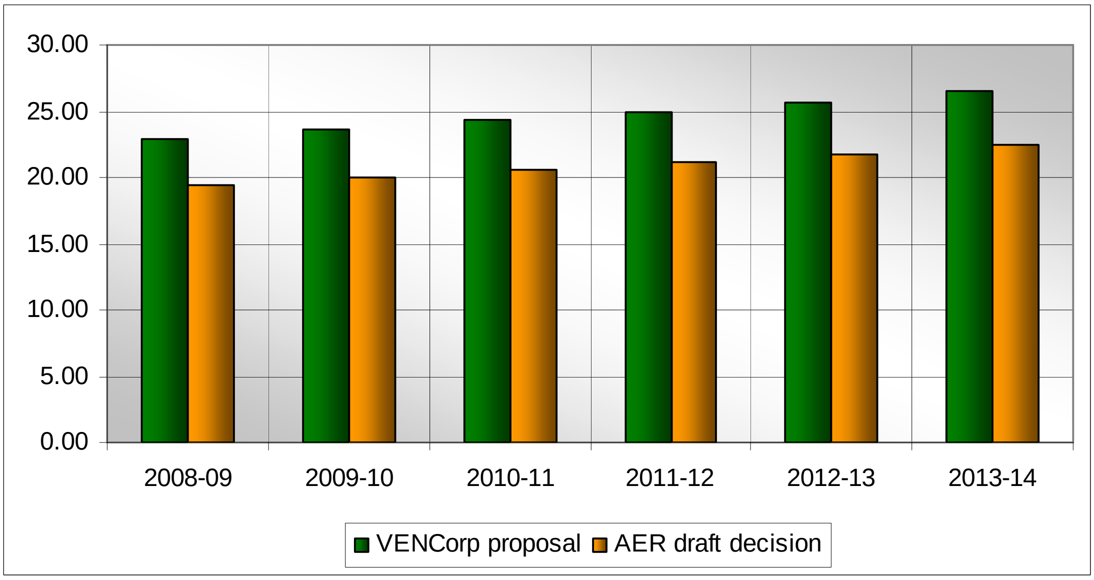
Table 3.2 AER's draft decision – Committed augmentation charges (nominal $m)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
VENCorp's proposal	22.9	23.6	24.3	25.0	25.7	26.5	148.0
AER's adjustment	-3.55	-3.67	-3.77	-3.86	-3.92	-4.07	-22.84
AER's draft decision	**19.35**	**19.93**	**20.53**	**21.14**	**21.78**	**22.43**	**125.16**

Source: VENCorp, AER analysis

The difference between the forecast committed augmentation charges in VENCorp's revenue proposal and the revised forecast approved in this draft decision is illustrated in figure 3.2 below.

Figure 3.2: AER's draft decision – Committed augmentation charges



Source: AER analysis

4 Forecast planned network augmentation expenditure and charges

4.1 Introduction

VENCorp plans and procures augmentation services under contract from SP AusNet and other owners of Victorian electricity transmission assets. The forecast of planned augmentation charges that VENCorp is required to include in its proposal to the AER relates to those components of its statutory electricity transmission-related costs that relate to what would otherwise form part of a TNSP's forecast capex for the relevant regulatory period, that is:

- all network charges payable by VENCorp to SP AusNet or any other owner of the Victorian Electricity Transmission Network or part of the Victorian Transmission Network, including charges relating to augmentation, and
- all other charges payable by VENCorp to providers of network support services and other services which VENCorp uses to provide network services that are transmission services.[73]

Where other TNSPs forecast capex, VENCorp derives a forecast of the contract charges that will be payable in the relevant regulatory period in respect of new contracts entered into for planned augmentations, on the basis of an indicative planned augmentation expenditure forecast. In VENCorp's proposal and this draft decision, this is referred to as VENCorp's forecast planned augmentation expenditure. The forecast of contract charges expected to flow from this expenditure is referred to as VENCorp's forecast planned augmentation charges. It is the forecast planned augmentation charges, not the forecast planned augmentation expenditure underlying it, which forms the building block in VENCorp's MAAR.

This chapter considers VENCorp's forecast planned network augmentation expenditure program and forecast planned augmentation charges for the forthcoming regulatory period.

4.2 Regulatory requirements

VENCorp's forecast planned augmentation charges are derived from an underlying forecast of planned augmentation expenditure which VENCorp submits is likely to occur within the forthcoming regulatory period, and estimates of the associated capital costs. These forecast costs are converted to forecast planned augmentation charges on the basis of a series of assumptions (WACC, depreciation over the life of a contract, associated opex) based on recent regulatory decisions and VENCorp's past experience in contracting for similar works.

The AER's review of VENCorp's forecast planned augmentation charges therefore necessarily involves a review of:

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[73] NER cl. 9.3.1(2).

- the forecast planned augmentation expenditure from which they have been calculated
- the methodology applied in calculating forecast charges on the basis of the forecast of expenditure and
- the forecast planned augmentation charges.

In assessing VENCorp's forecast of planned network augmentation expenditure, the AER has applied the provisions of cl. 6A.6.7 of the NER, which set out the requirements for the proposal and assessment of forecast capital expenditure, including augmentation expenditure.

Clause 9.8.4C(a) of the derogation requires that VENCorp's MAAR must be set on a full cost recovery, no operating surplus basis, so as not to exceed VENCorp's statutory electricity transmission related costs. The AER's assessment of the forecast planned augmentation charges that VENCorp proposes be included in its MAAR under cl. 6A.6.7 of the NER has been made in that context, and recognises the difference between the costs VENCorp seeks to recover through its forecast planned augmentation charges and those generally included in a TNSP's capex forecast.

4.2.1 Capex objectives

Clause 6A.6.7(a) of the NER provides that a TNSP must, in its revenue proposal, provide a forecast of the total capex that will be required in the relevant regulatory period in order to meet four prescribed objectives (the capex objectives), which are to:

1. meet the expected demand for prescribed transmission services over that period
2. comply with all applicable regulatory obligations associated with the provision of prescribed transmission services
3. maintain the quality, reliability and security of supply of prescribed transmission services and
4. maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

4.2.2 Capex criteria and factors

Clause 6A.6.7(c) of the NER provides that the AER must accept the forecast of capex included in a TNSP's revenue proposal if the AER is satisfied that it meets the capital expenditure criteria. Specifically, the AER must be satisfied that the proposed total forecast capex reasonably reflects the following criteria (the capex criteria):

1. the efficient costs of achieving the capital expenditure objectives
2. the costs that a prudent operator in the circumstances of the relevant TNSP would require to achieve the capital expenditure objectives and
3. a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

To make the required assessment against the capex criteria, the AER must have regard to the following factors (the capex factors), listed in cl. 6A.6.7(e) of the NER:

1. the information included in or accompanying the Revenue Proposal

2. submissions received in the course of consulting on the Revenue Proposal
3. such analysis as is undertaken by or for the AER and is published prior to or as part of the draft decision of the AER on the Revenue Proposal under rule 6A.12 or the final decision of the AER on the Revenue Proposal under rule 6A.13 (as the case may be)
4. benchmark capital expenditure that would be incurred by an efficient TNSP over the regulatory control period
5. the actual and expected capital expenditure of the Transmission Network Service Provider during any preceding regulatory control periods
6. the relative prices of operating and capital inputs
7. the substitution possibilities between operating and capital expenditure
8. whether the total labour costs included in the capital and operating expenditure forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period
9. the extent to which the forecast of required capital expenditure of the Transmission Network Service Provider is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms and
10. whether the forecast of required capital expenditure includes amounts relating to a project that should more appropriately be included as a contingent project under clause 6A.8.1(b).

Under cl. 6A.6.7(d) of the NER, if the AER is not satisfied that the TNSP's proposed total forecast capex reasonably reflects the capex criteria, taking into account the capex factors, the AER must not accept the proposed forecast.

If the AER does not accept the proposed total forecast capex, cl. 6A.14.1(2)(ii) of the NER requires the AER to include in its draft decision:

> …an estimate of the total of the Transmission Network Service Provider's required capital expenditure for the regulatory control period that the AER is satisfied reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors.

The AER believes that each of the capex criteria can be applied to VENCorp's forecast planned augmentation expenditure, although this must be done in a manner that recognises and is consistent with the special circumstances under which VENCorp operates.

In particular, not all of the capex factors are applicable to VENCorp. VENCorp's forecast planned augmentation expenditure does not identify any projects that should be treated as contingent projects under cl. 6A.8.1 of the NER. Accordingly, cl. 6A.6.7(e)(10) is not applicable to VENCorp. Rather, VENCorp has identified a number of projects for which, should the need arise, VENCorp states it will seek to reopen its MAAR under cl. 9.8.4C (g2) of the NER. Under this clause, VENCorp may apply to the AER for an adjustment to its MAAR if VENCorp's statutory electricity-transmission related costs exceed, or are expected to exceed, the amount assumed by the AER in making its determination.

In addition, the AER notes that:

- VENCorp has not advised of any related party contracts, and the AER has no cause to consider that VENCorp's forecast of planned augmentation expenditure is based on contracts with third parties that are not on arms length terms as contemplated by cl. 6A.6.7(e)(9).
- VENCorp is not subject to the AER's STPIS, and has not applied a labour cost escalator in deriving its forecast of planned augmentation expenditure, so that cl. 6A.6.7(e)(8) has no application in this instance.

4.3 VENCorp's proposal

VENCorp's initial proposal, submitted on 1 March 2007[74], contained a forecast of planned augmentation charges, and an underlying forecast of the planned augmentation expenditure from which the forecast charges were derived.

On 21 June 2007, VENCorp published its 2007 Electricity Annual Planning Report (2007 EAPR). On 19 July 2007 VENCorp submitted a reconciliation of its revenue proposal (the initial proposal) and the 2007 EAPR. The reconciliation presented revised forecasts of planned augmentation expenditure and planned augmentation charges. For the purposes of this draft decision, VENCorp's initial proposal as amended by the new information provided in the reconciliation of 19 July 2007 is referred to as the revised proposal. The AER's draft decision has been made on the revised proposal.

The initial and revised proposals are discussed in turn below.

4.3.1 VENCorp's initial proposal

As noted above, the forecast planned augmentation *charges* VENCorp will be required to pay in the forthcoming regulatory period are built on underlying forecast planned augmentation *expenditure* – that is, the capital cost of the projects VENCorp expects to procure within the regulatory period.

These forecast costs are converted to forecast planned augmentation charges on the basis of a series of assumptions (WACC, depreciation over the life of a contract, associated opex) based on recent regulatory decisions and VENCorp's past experience in contracting for similar works.

These two elements of VENCorp's initial proposal, and the forecast of demand on which they are based, are summarised below.

4.3.1.1 Forecast planned augmentation expenditure

Demand forecasts

In preparing its 2006 EAPR, VENCorp engaged the National Institute of Economic and Industry Research (NIEIR) to prepare long-term forecasts of energy and electricity demand in Victoria for low, medium and high economic growth scenarios.

[74] An amended proposal was submitted to, and published by, the AER on 1 May 2007 after additional information was sought under cl. 6A.11 of the NER.

In its revenue proposal, VENCorp submits that annual energy consumption is forecast to grow to 53 383 GWh by the end of the forthcoming regulatory period, at an average rate of 0.4%. VENCorp notes that this is weaker than average growth over the current regulatory period of 1.5%. VENCorp attributes this to a combination of projected slower growth in the GSP, and Commonwealth and State government greenhouse gas initiatives.[75]

VENCorp's proposal also states that the 10% Probability of Exceedence (PoE) summer maximum demand is projected to grow from 10 683 MW to 11 627 MW over the forthcoming regulatory period at an average rate of 1.7%. The moderating penetration of air conditioning, the potential impacts of greenhouse gas initiatives and the projected increase in non-scheduled generation are cited as reasons for the difference between this and the much stronger average growth of 3.3% per annum over the current regulatory period. VENCorp expects winter maximum demand to grow at a lower rate of 1.1% over the same period, because of the dominance of gas heating in Victoria.[76]

Forecast planned augmentation expenditure

VENCorp's forecast planned augmentation expenditure is comprised of three types of augmentations:

- predominately load driven augmentations
- predominately generation driven augmentations and
- export driven augmentations.

VENCorp's initial revenue proposal forecast $354m of expenditure on network augmentation over the forthcoming period.[77] This represents an increase of approximately 150% from the actual expenditure in the current period. In forecasting its augmentation requirements, VENCorp has employed an indicative probabilistic planning methodology, developing four supply scenarios and two export scenarios. The four supply scenarios are:

Scenario 1: Predominately Latrobe Valley generation

Scenario 2: Predominately South West generation

Scenario 3: Increase in import from Snowy/NSW and

Scenario 4: High Metropolitan and State Grid generation.

VENCorp explains the indicative probabilistic approach it has adopted as:

> the practice of applying judgements to projects which have not been subjected to detailed probabilistic assessments but for which VENCorp has conducted detailed assessment using the N-0 secure and N-1 secure criteria.[78]

[75] VENCorp, *VENCorp Electricity Revenue Cap Proposal – 1 July 2008 to 30 June 2014*, p.27
[76] ibid.
[77] ibid., p. 33
[78] VENCorp, email to PB, 16 May 2007.

In practice, this approach is based on a deterministic analysis, combined with VENCorp's previous experience of probabilistic assessments.[79] VENCorp states that it has applied this approach to all projects contained in its revenue proposal.[80] This approach is consistent with the way that VENCorp plans projects in the six to ten year outlook in its EAPRs.

In calculating the $354m forecast of augmentation expenditure for the forthcoming regulatory period, VENCorp has applied an equal weighting of 25% to each of the four scenarios. Projects that are required in all four scenarios are referred to as 'predominately load driven' or 'must do' works. These are projects that VENCorp submits will be required regardless of the location of new generation. VENCorp's forecast planned augmentation expenditure includes 100% of the estimated cost of these projects. Projects that are only needed in certain scenarios are referred to as 'predominately generation driven' or 'scenario driven' works. For each scenario in which a forecast generation driven or scenario driven project appears, 25% of the estimated project cost has been included in VENCorp's forecast planned augmentation expenditure.[81]

VENCorp explains that the increase in the augmentation expenditure for the forthcoming period is driven by the increase from a five to six year regulatory period,[82] and the increasing cost of network assets around the globe.[83] The basis of the cost estimates for most projects contained in VENCorp's forecast of planned augmentation expenditure are cost estimates provided by SP AusNet to VENCorp for the purpose of its EAPR planning process. These cost estimates are prepared with a ±25% variance.[84] Citing rising prices, VENCorp based its initial revenue proposal on the upper bound of SP AusNet's cost estimates, applying a uniform +25% upward adjustment to the core estimates for all projects in its forecast planned augmentation expenditure. VENCorp states that, where possible, it applies a due diligence process which compares the estimates provided by SP AusNet against the cost of recently completed projects.[85]

Predominately load driven augmentation

Located mainly in the metropolitan area, load driven augmentations are those required due to an increase in load growth, regardless of where new generation locates.

VENCorp also proposes to include in its forecast allowances for small and minor network augmentations over the forthcoming regulatory period including:

- fault level mitigation works
- line termination upgrades
- secondary equipment

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[79] VENCorp, *op cit*, – explanation for planned augmentation program, version 2.4.
[80] VENCorp, email to PB, 16 May 2007.
[81] For example, a project with an estimated cost of $20m appearing in only one scenario would produce forecast expenditure of $5m ($20m x 25%). If it appeared in two scenarios, the associated forecast expenditure would be $10m, and so on.
[82] The duration of VENCorp's current regulatory period is five and a half years.
[83] VENCorp, *op cit*, p.30
[84] For example, Letter, SP AusNet to VENCorp, *Planning Estimates*, 15 June 2005.
[85] VENCorp, *op cit*, p.30

- dynamic system and supply of quality monitoring equipment and
- reactive support.

The total forecast expenditure in the initial proposal for all predominately load driven augmentation over the forthcoming regulatory period is $227m.

Predominately generation driven augmentation

While the augmentations included in this category are required to meet load growth, VENCorp submits that the need for particular augmentations is dependent on the timing and location of new generation in the network. Due to the difficulty in forecasting these variables, VENCorp has not locked in certain dates for these projects, but has spread the cost of these augmentations evenly across the last four years of the forthcoming regulatory period (2010–12 to 2013–14).[86]

The total, unweighted, expenditure associated with each scenario is shown in table 4.1.

Table 4.1 Forecast planned network augmentation for the forthcoming period — by scenario (unweighted, $m, 2007–08)

	Latrobe valley	Southwest Victorian	Import from Snowy/NSW	Metropolitan & state grid/DSM
Forecast planned augmentation by scenario	138	83	164	125

Source: VENCorp spreadsheet #194410.

VENCorp submits that each of its four scenarios has an equal probability of occurring. Therefore, it has applied an equal weighting of 25% to each scenario to arrive at a proposed forecast of total generation driven augmentation expenditure of $127m.

Export driven augmentation

VENCorp's initial proposal identifies a number of potential augmentations which are needed to increase Victoria's export capacity during times of light load. Due to the uncertainty surrounding these projects, VENCorp has not included any allowance for these projects in its revenue proposal, and has instead foreshadowed its intention to apply to the AER for a MAAR adjustment under cl. 9.8.4C(g2) of the NER should the need for one or more of these projects arise during the forthcoming regulatory period.[87]

[86] VENCorp, *op cit*, p. 33 VENCorp's revenue cap proposal incorrectly states on p.31 that the generation driven augmentations are spread evenly over the last three years of the forthcoming regulatory period. The actual timeframe used by VENCorp in its proposal is the final four years, from 2010–11 to 2013–14, as stated on p.33 of its proposal.

[87] VENCorp, *op cit*, p. 32

Funded augmentation

VENCorp notes that some of the predominately load and generation driven augmentations may be displaced during the forthcoming regulatory period with funded augmentations[88] resulting from new connections. Again, VENCorp notes the uncertainty surrounding the size, timing and location of such augmentations, and has not sought to address this issue when deriving its forecast.[89]

4.3.1.2 Forecast planned augmentation charges

Unlike other TNSPs, VENCorp does not forecast its revenue requirement on the basis of forecast network augmentation expenditure over the regulatory period, but rather on a forecast of the costs that will actually be incurred by VENCorp in procuring augmentations within the regulatory period, and the amount of those costs which will be payable through contracts charges in the relevant regulatory period. As such, the MAAR set by the AER for VENCorp is calculated on a forecast of planned network augmentation charges, rather than the forecast network augmentation expenditure that underlies it.

VENCorp states that, for the purposes of its initial revenue proposal, it has converted forecast network expenditure into forecast charges by applying a nominal vanilla WACC of 8.5% and straight-line current cost depreciation charge over 30 years.[90] Applying this forecasting methodology, VENCorp produced the forecast planned augmentation charges in table 4.2 below.

Table 4.2 VENCorp's forecast planned augmentation expenditure and charges

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Forecast planned augmentation expenditure ($m, 2007–08)	2.0	15.6	51.7	79.3	138.0	67.3	354
Forecast planned augmentation charges ($m, nominal)	0.2	1.7	6.8	15.8	31.8	43.0	99.3

Source: VENCorp's initial revenue proposal, pp.33, 44.

This forecast of planned augmentation charges has been developed solely for the purpose of VENCorp's revenue proposal, in order to determine the appropriate allowance for planned augmentation charges to be included in VENCorp's MAAR for the forthcoming regulatory period. VENCorp states that, while the forecast planned augmentation charges are based on what VENCorp considers to be reasonable estimates for the purposes of its revenue proposal, the actual charges payable will be based on the outcomes of regulatory test assessments, competitive tendering provisions or directions of VENCorp throughout the regulatory period.

[88] A funded augmentation is a transmission network augmentation for which a TNSP is not entitled to receive a charge. These are treated by VENCorp in accordance with the principles set out in its Connection Augmentation Guidelines.
[89] VENCorp, *op cit*, p. 32
[90] ibid., p. 33

VENCorp notes that when it enters into agreements with parties for the provision of services it typically receives a schedule of annual charges for the life of the project, and that the agreements are not based on a WACC determined by VENCorp. Financing charges are determined at the time that VENCorp enters into contracts with third parties for augmentations. Similarly, VENCorp notes that the 30 year depreciation schedule used for the purposes of its forecast is based on an average of current projects, and the expected timeframe for a number of projects included in its forecast of planned augmentation expenditure. The length of contracts entered into in the forthcoming regulatory period will depend on the nature of the relevant projects.[91]

4.3.2 Reconciliation of revenue proposal with the 2007 EAPR

On 21 June 2007, VENCorp released its 2007 EAPR. On 19 July 2007, VENCorp provided the AER with a reconciliation of its revenue proposal with the 2007 EAPR. This included a project-by-project reconciliation with the forecast planned augmentation expenditure in its initial proposal, and revised forecast planned augmentation charges. VENCorp advised that the changes to its revenue proposal arise from either:

- additional studies undertaken for the 2007 EAPR or
- changes in cost estimates.[92]

4.3.2.1 Forecast planned augmentation expenditure

Demand forecasts

Due to the timing of the publication of the 2007 EAPR, it was not possible for VENCorp to update its revenue proposal to take into account this new information. This is consistent with its planning approach, as VENCorp uses the load forecast published in the 2006 EAPR as the basis for its 2007 EAPR. There is, in effect, a one year lag between the publication of a load forecast in the EAPR and its application to the planning components of the subsequent EAPR.

Forecast planned augmentation expenditure

The majority of the changes to VENCorp's forecast of planned augmentation expenditure relate to the changes in the cost estimates for individual projects. These changes to cost estimates originate from either revised cost estimates provided by SP AusNet at VENCorp's request, or "rule of thumb" cost extrapolations applied by VENCorp on the basis of SP AusNet's revised estimates. VENCorp's rule of thumb cost extrapolations are discussed in section 4.9.3 of this draft decision.

Table 4.3 shows the impact of the revised proposal on the predominately load driven projects, while table 4.4 shows the impact on generation driven augmentation.

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[91] ibid., p. 33
[92] VENCorp, letter to the AER, *Reconciliation of VENCorp Electricity Transmission Network Revenue Proposal for the Period 1 July 2008 to 30 June 2014 with the 2007 Electricity Annual Planning Report*, 19 July 2007, p.5

Table 4.3 VENCorp's initial and revised proposals — Predominately load driven expenditure ($m, 2007–08)

	20008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Total
VENCorp's initial proposal	2	15.6	19.9	47.5	106.3	35.5	226.8
VENCorp's revised proposal	2.6	9.3	10.5	42.0	43.0	49.4	156.8
Difference	0.6	-6.3	-9.4	-5.5	-63.3	13.9	-70.0

Source: VENDOCS #194410, #215180 and AER analysis.

Table 4.4 VENCorp's initial and revised proposals — Predominately generation driven expenditure ($m, 2007–08)

	Latrobe valley	Southwest Victorian	Import from Snowy/NSW	Metropolitan & state grid/DSM	Total
Initial proposal					
Total expenditure	138	83	164	125	
Weighted expenditure	34	21	41	31	127
Revised proposal					
Total expenditure	140	88	175	124	
Difference - total expenditure	*2*	*5*	*11*	*-1*	
Weighted expenditure	35	22	44	31	132
Difference - weighted expenditure	*1*	*1*	*3*	-	*5*

Source: VENDOCS #194410, #215183 and AER analysis.

Table 4.5 shows the impact of the 2007 EAPR on VENCorp's total forecast planned augmentation expenditure.

Table 4.5 VENCorp's revised proposal — Total forecast planned augmentation expenditure ($m, 2007–08)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Total
VENCorp's initial proposal	2.0	15.6	51.7	79.3	138.0	67.3	353.9
VENCorp's revised proposal	2.6	9.3	43.3	74.8	75.8	82.2	288.2
Difference	0.6	-6.3	-8.4	-4.5	-62.2	14.9	-65.7

Source: VENDOCS #194410, #215183 and AER analysis.

The greatest impact on the level of the proposed forecast is the removal of the +25% cost multiplier that VENCorp had incorporated into its initial proposal. VENCorp states that it believes that removing the multiplier is the most prudent approach to adopt at this stage.[93]

4.3.2.2 Forecast planned augmentation charges

In its initial revenue proposal VENCorp calculated its forecast planned augmentation charges assuming a nominal vanilla WACC of 8.5% and a straight line current cost depreciation charge over 30 years.

In calculating the adjusted forecast planned augmentation charges in its revised proposal, VENCorp has also included an allowance of 1.5% of capital costs per annum for operating and maintenance expenditure. VENCorp submits that in the absence of such a provision the forecast of charges may not adequately reflect the charges that VENCorp may reasonably incur in the provision of transmission services in Victoria.[94]

VENCorp's revised forecast planned augmentation charges are shown in table 4.6 below.

Table 4.6 VENCorp's revised proposal — Total forecast planned augmentation charges ($m, nominal excluding GST)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Total
VENCorp's initial proposal	0.2	1.7	6.8	15.8	31.8	43.0	99.3
VENCorp's revised proposal	0.4	1.4	6.9	14.0	18.0	22.5	63.2
Difference	0.2	-0.3	0.1	-1.8	-13.8	-20.5	-36.1

Source: VENCorp revenue proposal, p.34; VENCorp, letter to the AER, 19 July 2007, p. 5 and AER analysis.

[93] ibid.
[94] ibid.

4.4 VENCorp's augmentation planning process

VENCorp's approach to network planning is set out in two key documents: the Electricity Transmission Network Planning Criteria (May 2007); and Victorian Electricity Transmission Connection Augmentation Guidelines (August 2005), both of which are published by VENCorp. VENCorp publishes the results of its planning studies in its Electricity Annual Planning Report (EAPR), which is intended to inform interested parties of existing or potential network constraints and facilitate the development of the shared transmission network. These three documents are considered in turn below.

4.4.1 VENCorp's Electricity Transmission Network Planning Criteria

VENCorp's Electricity Transmission Network Planning Criteria (May 2007) set out the assumptions underlying its approach to planning, and define how certain obligations are to be modelled or assessed. VENCorp states that its planning approach is aimed at ensuring that the system security and performance obligations in the NER are achieved in the most economic way using the markets benefits limb of the regulatory test.[95] In brief, VENCorp's approach is to undertake a technical assessment of the power system, which requires:

- *Market analysis* — produces various demand and generation scenarios, and provides hour-by-hour demand and generation dispatch and costs across the network.
- *Network analysis* — calculates network loading under the range of system conditions defined by the market analysis.
- *Systems operations analysis* — determines the operational actions to ensure compliance with the system security obligations. Probabilities are then applied to these actions to account for uncertainty.[96]

4.4.2 VENCorp's connection augmentation guidelines

As the entity responsible for augmentations to the Victorian shared network, VENCorp must assess and advise on issues associated with any augmentations to facilitate network connections. VENCorp's connection augmentation guidelines are intended to identify circumstances where a connection applicant may be required to fund an augmentation to facilitate its connection, and also to identify when VENCorp may undertake any necessary augmentation.[97] The guidelines set out VENCorp's approach to allocating the augmentation costs arising from any new connection between network users and the connection applicant.

4.4.3 VENCorp's EAPR process

In executing its statutory planning responsibilities, VENCorp produces an annual planning document called the EAPR. The purpose of the EAPR is to enable market participants and other interested parties to formulate and propose options to relieve

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[95] VENCorp, *op cit*, p. 15
[96] VENCorp, *Victorian Electricity Transmission Network Planning Criteria*, May 2007, p.16
[97] VENCorp, *Victorian Electricity Transmission Network Connection Augmentation Guidelines*, August 2005, p.4

identified constraints.[98] A key part of the EAPR is the economic evaluation of potential options to alleviate identified constraints. In identifying emerging constraints, the EAPR applies a different methodology over the first five years to that applied for years six to ten:

4.4.3.1 Five-year analysis

The 2007 EAPR states that for the first five years of the forecast period, VENCorp performs a "detailed probabilistic analysis" for each region, based on a simulation that uses extrapolated NEM dispatch data to determine probable shared transmission usage.[99] Once VENCorp has undertaken an analysis of the market and the network, it employs a probabilistic approach to the possible operational responses to account for uncertainties such as demand, generation, unavailability and network contingencies.[100]

4.4.3.2 Ten-year analysis

VENCorp explains that the objective of the ten year outlook included in its EAPRs is to provide an indication of potential network constraints that may occur in the ten year period, together with feasible transmission network options and indicative timing to remove the network constraints.[101] VENCorp states that while it is appropriate, and possible, to accurately forecast demand, it is not possible to forecast generation with the same degree of certainty, as the location of new generation can have a considerable effect on the pattern of power flows and system constraints.[102] VENCorp also states that due to the lower degree of confidence attaining to this period, possible augmentation timings are indicative only. To overcome this uncertainty, VENCorp has adopted a "scenarios planning approach" which involves the modelling of a number of possible generation patterns over the following ten years.[103] VENCorp states:

> The scenario analysis overlays an 'indicative probabilistic' assessment of constraints which incorporates deterministic and limited probabilistic analysis.[104]

4.5 Submissions

The EUCV made the following comments in relation to VENCorp's proposed forecast of planned augmentation expenditure and charges:

> The AER should assess why assets should be depreciated over a period that is less than the period of their economic life and should verify that consumers are not being charged twice for assets that have been fully depreciated.
>
> Consumers should only pay for those projects that are directly related to the level of demand.[105]

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[98] VENCorp, 2007 EAPR, p.1
[99] ibid., p.48
[100] ibid., p.86
[101] VENCorp, *Process: Electricity annual planning report, DAM 002-09 Ten year electricity outlook*, p.5
[102] VENCorp, 2007 EAPR, p.88
[103] See page 88 of the 2007 EAPR for details of the current scenarios developed by VENCorp.
[104] VENCorp, 2007 EAPR, p.48.

4.6 Consultants' review

The AER engaged specialised engineering consultants to assist in its review of VENCorp's forecast planned augmentation expenditure.

The AER's analysis of VENCorp's forecast planned augmentation expenditure and its consideration of the advice of its consultants is set out in section 4.7 below, and in appendix A.

4.6.1 PB's review of VENCorp's initial proposal

The AER engaged PB to provide an independent assessment of the forecast planned augmentation expenditure for the forthcoming regulatory period in VENCorp's initial proposal.[106]

PB was also required to review the appropriateness of VENCorp's capital governance framework, including strategies, policies and procedures.

VENCorp's reconciliation of its initial proposal and the 2007 EAPR was submitted at the conclusion of PB's review, and has therefore not been considered by PB. PB's report relates only to VENCorp's initial proposal and the information submitted prior to the release of the 2007 EAPR.

4.6.2 Nuttall Consulting's review of VENCorp's revised proposal

The AER engaged Nuttall Consulting (NC) to conduct an independent assessment of the impact of VENCorp's 2007 EAPR, released in June 2007 at the end of the PB review, on the recommendations in PB's report to the AER.

NC has not, and was not requested to, review PB's report to the AER. In assessing the impact of the 2007 EAPR on PB's recommendations, NC has proceeded on the assumption that those recommendations are valid.

4.7 Issues and AER's considerations

VENCorp has developed its forecast of planned augmentation charges in two stages:

- Forecast planned augmentation expenditure has been derived from information in VENCorp's 2006 EAPR. Project costs are based on either cost estimates provided to VENCorp by SP AusNet, or on VENCorp's own estimates. In July 2007 this forecast planned augmentation expenditure was updated following the release of the 2007 EAPR.
- Forecast planned augmentation charges are derived from the underlying forecast of planned augmentation expenditure using a series of assumptions based on existing contracts and recent regulatory decisions.

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[105] Victorian Electricity Transmission Revenue Reset – *A response by Energy Users Coalition of Victoria – June 2007* p. 11

[106] VENCorp's reconciliation of its initial proposal and the 2007 EAPR was submitted at the conclusion of PB's review, and has therefore not been considered by PB. PB's report relates only to VENCorp's initial proposal and the information submitted prior to the release of the 2007 EAPR.

The AER's assessment of VENCorp's forecast augmentation requirements is set out in the same two stages, and in the context of VENCorp's capital governance framework relating to its statutory electricity transmission related functions.

- Section 4.7.1 examines VENCorp's corporate governance framework, in particular its arrangements for the approvals network augmentations
- Section 4.7.2 considers VENCorp's forecast planned augmentation expenditure
- Section 4.7.3 considers VENCorp's forecast planned augmentation charges, and sets out the AER's draft decision on the appropriate allowance for these charges to be included in VENCorp's MAAR.

4.7.1 VENCorp's capital governance framework

This section examines VENCorp's corporate governance framework, in particular its arrangements for the approval of network augmentations.

4.7.1.1 VENCorp's proposal

VENCorp referred the AER to several key documents that contribute to its governance arrangements for the approval of new augmentations to the Victorian network. The six stages, and the key documents feeding into each, are summarised below.

1. *Planning and project identification* — VENCorp's EAPRs contain the results of its annual planning reviews. The planning approach used by VENCorp in formulating the EAPR is explained in its Victorian Electricity Transmission Network Planning Criteria. It is also at this stage that VENCorp would proceed with its regulatory test consultation period (the regulatory test consultation time frame is project specific).
2. *Project approval* — once a project has passed the regulatory test, either the CEO or the VENCorp Board are required to grant authority to proceed. VENCorp has developed a Delegations of Authority Policy pursuant to its Deed of Delegation that provides that VENCorp's CEO can authorise projects of up to $1 million, while any project above this amount must receive Board approval.
3. *Procurement* — when assessing whether or not an augmentation should be subject to a competitive tender process, VENCorp is subject to the Essential Services Commission's Electricity Industry Guideline No. 18 — Augmentation and land access guidelines.[107] For high risk or high cost projects, VENCorp states that it establishes a steering committee, which generally consists of members of VENCorp's senior management team, to oversee the procurement process.
4. *Contract negotiation* — VENCorp has a standard contract which forms the basis of its negotiations for contestable works. For non-contestable works VENCorp will enter into a network services agreement with SP AusNet. All contracts are signed by the CEO with Board approval.

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[107] cl. 2.2(a) of the Electricity Industry Guideline No. 18 — Augmentation and land access guidelines states that an augmentation is contestable if the capital cost is reasonably expected to exceed $10m, and that the augmentation is separable.

5. *Contract/project monitoring* — VENCorp monitors the progress of projects through regular contact with the contracting parties. VENCorp states that it is in the process of implementing a contract management system to manage this process.

6. *Reporting* —VENCorp's Board receives monthly updates on significant projects including a risk management report.

4.7.1.2 PB's review

PB undertook a high level review of VENCorp's network augmentation governance arrangements. It concludes that:

- VENCorp's governance arrangements are typical of a well governed, integrated business
- VENCorp's capex and opex approvals processes are both sound and appropriate for a corporation such as VENCorp
- VENCorp's dependence on SP AusNet for project cost estimates may limit its understanding of up to date market conditions for materials and labour. Further advice from third parties may capture some efficiency gains.[108]

4.7.1.3 AER's considerations

The AER agrees with PB's conclusion that VENCorp has established appropriate governance arrangements for its statutory electricity transmission related functions.

4.7.2 VENCorp's forecast planned augmentation expenditure

The AER's considerations of the forecast planned augmentation expenditure that VENCorp has prepared for the purposes of its revenue proposal are set out in sections 4.7.2.1 to 4.7.2.6 below.

- Section 4.7.2.1 considers VENCorp's forecasting methodology
- Section 4.7.2.2 considers the demand forecast underlying VENCorp's forecast planned augmentation expenditure
- Section 4.7.2.3 considers the cost estimates on which VENCorp has built its forecast planned augmentation expenditure
- Section 4.7.2.4 considers the detailed review of a sample of the projects making up VENCorp's forecast planned augmentation expenditure
- Section 4.7.2.5 considers the extension of the findings of those detailed project reviews to the remainder of VENCorp's forecast planned augmentation expenditure
- Section 4.7.2.6 considers VENCorp's expenditure on committed augmentations from the current regulatory period and the relevance of VENCorp's previous investment decisions to the AER's assessment of its forecast planned augmentation expenditure for the forthcoming regulatory period.

[108] PB Strategic Consulting, *VENCorp revenue reset – An independent review – Prepared for AER, 8 October 2007* p.113-14

4.7.2.1 VENCorp's forecasting methodology for the purposes of its revenue proposal

VENCorp's proposal

VENCorp states that it has prepared its forecast of planned augmentation expenditure for the regulatory period commencing 1 July 2008 using the indicative probabilistic approach[109] it applies in the ten year outlook contained in its EAPRs.[110] In developing a forecast of planned augmentation expenditure for the purposes of its revenue proposal VENCorp has relied heavily on the information presented in chapter 7 of its 2006 EAPR.[111] The 2006 EAPR states that:

> The scope of VENCorp's Electricity Annual Planning Report is confined to assessing the adequacy of the Victorian shared transmission network to meet Victorian load growth over the next 10 years.[112]

In preparing the forecast of planned augmentation expenditure in its revenue proposal, VENCorp has not undertaken detailed technical probabilistic or economic studies for any project.[113] Rather, the approach adopted is consistent with the high level planning VENCorp undertakes for the ten-year outlook (which covers years six to ten) contained in its EAPRs and accords with its planning document, Victorian electricity transmission network planning criteria, which outlines the 'market benefits' approach VENCorp takes to planning. This approach quantifies the costs and benefits of relieving any particular constraint through various options. The benefits predominately take the form of a reduction in lost load, measured by the 'value of customer reliability', [114] while costs include the construction of new assets. VENCorp sources estimates of these costs from SP AusNet, and its own past experience. VENCorp states that it subjects the SP AusNet cost estimates to due diligence where possible, by comparing them with the cost of similar projects that have recently been completed.[115]

VENCorp states that under the framework in which it operates, it is only able to recover those charges that are required to meet its statutory electricity related functions.[116] These charges are largely determined by the actual cost of the contracts that VENCorp entered into to procure transmission services, and are not based on the allowance set by the AER. VENCorp believes that:

> …the AER has the ability to consider [VENCorp's forecast planned augmentation expenditure] in a different manner to the way in which it considers information presented by other TNSPs.[117]

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[109] See section 4.4 of this document for an overview of VENCorp's indicative probabilistic approach.
[110] VENCorp, *VENCorp electricity revenue cap proposal — explanation for planned augmentation program*, version 2.4, p.4
[111] VENCorp used an updated load forecast to the forecast that underpins the 2006 EAPR.
[112] VENCorp, 2006 EAPR, p.2
[113] VENCorp, *VENCorp electricity revenue cap proposal — explanation for planned augmentation program, version 2.4*, p.1
[114] Charles River Associates, *Assessment of the Value of Customer Reliability (VCR)*, prepared for VENCorp, December 2002
[115] VENCorp, *op cit*, p. 30
[116] VENCorp letter, *op cit*, p. 4
[117] ibid.

Consultant's review

PB states that the process VENCorp uses follows a "relatively simplistic approach",[118] commenting that VENCorp has not attempted to account for any interdependencies between projects and has not modelled any of the forecast projects as part of its technical load-flow analysis.

PB comments that the outcome of the 'indicative probabilistic' approach applied by VENCorp in developing the forecast planned augmentation expenditure for its revenue proposal is that:

> The projects and their timing (where identified) are indicative only, and may be subject to considerable variations should any of the vast array of input assumptions used in the detailed assessment change.[119]

AER's considerations

In its review of VENCorp's revenue proposal the AER has applied the provisions of chapter 6A subject to the modifications set out in the jurisdictional derogation for Victoria in chapter 9, and with due regard to the nature of VENCorp's statutory electricity transmission related functions. The NER are clear in requiring the AER to conduct its assessment of revenue proposals in the context of the unique circumstances of the proponent TNSP, and it is clear that VENCorp has a greater claim to uniqueness than most.

The approach taken by VENCorp in preparing its forecast planned augmentation expenditure lacks the degree of rigour typically applied in the development of a revenue proposal. In particular, the AER notes that VENCorp's use of the ten-year outlook methodology for the purposes of its revenue proposal does not appear consistent with the planning approach VENCorp itself will apply in its EAPR process in the regulatory period to which the proposal relates. The EAPR process will involve detailed probabilistic analysis over the first five years of the forecast period, and scenario based indicative probabilistic analysis only from years six to ten.

4.7.2.2 Demand forecasts underpinning VENCorp's revenue proposal

VENCorp's initial proposal

The demand forecast underpinning both VENCorp's revenue proposal and the 2006 EAPR are developed by NIEIR. NIEIR used an integrated multi purpose model that links economic projections to energy forecasts.[120]

VENCorp has developed its forecast planned augmentation using figures consistent with those applied to the studies undertaken in the 2006 EAPR. VENCorp has used the summer maximum demand figure of 11 627 MW, which assumes a 10% PoE, and the medium economic growth scenario. For the purposes of comparison, table 4.7 compares the 10% PoE, 50% PoE and the 90% PoE across the medium economic growth scenario.

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[118] PB Strategic Consulting, *op cit*, p.59
[119] ibid, p. 60
[120] The methodology and assumptions used by NIEIR can be found at appendix A3 of VENCorp's 2006 EAPR.

Table 4.7 Victorian summer maximum demand forecasts — Medium economic growth scenario

Year	10% PoE		50% PoE		90% PoE	
	(MW)	Growth (%)	(MW)	Growth (%)	(MW)	Growth (%)
2006–07	10 234	–	9 421	–	8 981	–
2007–08	10 473	2.3	9 627	2.2	9 170	2.1
2008–09	10 683	2.0	9 805	1.8	9 331	1.8
2009–10	10 819	1.3	9 914	1.1	9 424	1.0
2010–11	10 990	1.6	10 057	1.4	9 553	1.4
2011–12	11 163	1.6	10 203	1.5	9 684	1.4
2012–13	11 415	2.3	10 428	2.2	9 894	2.2
2013–14	11 627	1.9	10 613	1.8	10 065	1.7
2014–15	11 837	1.8	10 802	1.8	12 243	1.8
2015–16	12076	2.0	11 020	2.0	10 449	2.0

Source: PB using VENCorp's 2006 EAPR.

VENCorp states that to meet this demand, approximately 1 500 MW of additional generation will be required in Victoria by 2012–14. The supply and demand balance for 2013–14 is shown in table 4.8.

Table 4.8 Victorian generation and load balance for 2013–14

Demand	Victorian maximum demand (10% PoE)	11 627
	Export to South Australia	500
	Victorian reserve level	265
	Total demand (plus reserve level)	12 392
Supply	Total supply	10 969
Additional generation required		1 423

Source: VENCorp's initial proposal, p.28.

As the location and size of new generation is unknown, VENCorp has developed generation scenarios to model the likely location of this new generation. VENCorp has used the forecast requirement of 1 500 MW additional generation when developing its scenarios. The four generation scenarios developed by VENCorp and used in its revenue proposal are set out in table 4.9.

Table 4.9 VENCorp's generation scenarios

		Source of new generation (MW)				
Scenario	**Description**	**Increased Latrobe valley generation**	**Increased SW Victoria generation**	**Increase import from Snowy/NSW**	**Metropolitan & State Grid generation/DSM**	**Total additional supply (MW)**
1	Latrobe valley	1 200	–	–	300	1 500
2	South western Victoria	200	700	–	600	1 500
3	Increased import from	600	–	600	300	1 500
4	Metro & State grid/DSM	300	–	–	1 200	1 500

Source: VENCorp's initial revenue proposal, p.29.

Consultant's review

PB reviewed the demand forecasts that underpin VENCorp's forecast planned augmentation and made the following observations:

- there is a reasonably strong correlation between Victorian Gross State Product projections and the medium economic scenario
- the maximum demand forecasts are more sensitive to variance in the ambient temperature (PoE assumptions) than to economic growth forecasts, and
- the 2013–14 50% PoE maximum demand is less than the 2008–09 10% PoE, indicating that the influence of temperature sensitivity between the 10% PoE and 50% PoE can be up to 5 years.[121]

AER's considerations

The AER is satisfied that the load forecast underlying VENCorp's revenue proposal is a realistic expectation of the level of forecast demand over the forthcoming period as required by cl. 6A.6.7(c)(3). The AER notes that VENCorp has based its revenue proposal on the summer maximum demand, assuming a 10% PoE assumption in relation to the long run average weather conditions, and the medium economic growth scenario. The AER also notes PB's observation that there is a significant difference in maximum demand between the 10% PoE and the 50% PoE temperature conditions. As PB indicates, the 10% PoE maximum demand approximates to a five year advancement on the 50% PoE maximum demand.

The AER notes that VENCorp's generation scenarios have been presented on a consistent basis with those developed and used in the 2006 EAPR, and considers that they have been developed in an appropriate manner.

[121] PB Strategic Consulting, *op cit*, p.56

Impact of revised load forecast contained in 2007 EAPR

Due to the timing of the publication of the 2007 EAPR, it was not possible for VENCorp to update its revenue proposal to take into account the new load forecast contained in the 2007 EAPR. This is consistent with its planning approach, as VENCorp uses the load forecast published in the 2006 EAPR in its 2007 EAPR. There is, in effect, a one year lag between the publication of a load forecast in the EAPR and its application to the planning components of the subsequent EAPR.

Consultant's review

NC states that, based on the 2007 EAPR, the summer maximum demand (10% PoE) will be approximately 450 MW less than that assumed in VENCorp's initial and revised revenue proposals, and that this equates to an approximate two year deferment in the maximum demand levels.[122]

The generation scenarios developed by VENCorp are calculated using the maximum demand that must be met by scheduled generation in that year. The maximum demand is used to calculate the amount of additional scheduled generation required to ensure supply equals demand. NC has recalculated the generation scenarios using the load forecast from the 2007 EAPR. This calculation shows that at least 929 MW of additional generation will be required by 2013–14. This represents a reduction of approximately 550 MW from that assumed in VENCorp's original and revised proposals.[123] NC concludes that the impact of the 2007 EAPR load forecast will be to defer VENCorp's forecast planned augmentation needs.[124] Specifically, NC states that the reduced maximum demand will tend to defer the load driven projects, while the reduction to the additional generation required in the scenarios will tend to defer the generation driven projects.[125]

AER's considerations

As noted by NC, the 2007 EAPR load forecast is lower than that contained in VENCorp's revenue proposal and its 2006 EAPR. The AER notes the timing of the publication of the 2007 EAPR, and recognises that it would not be practical for VENCorp to have updated its revenue proposal to take into account this new information. However, in its assessment of VENCorp's revenue proposal the AER considered it prudent to take into account this more recent information, and accepts NC's view that the lower maximum demand contained in the 2007 EAPR load forecast — and the reduction in additional generation required in VENCorp's generation scenarios — will result in deferment of augmentation needs over the forthcoming regulatory period. The AER has taken this more recent information into account in its assessment of VENCorp's forecast planned augmentation expenditure.

[122] Nuttall Consulting, *VENCorp's revenue proposal and reconciliation to the 2007 EAPR*, 9 October 2007, p. 49
[123] ibid, p. 50–51
[124] ibid.
[125] ibid.

4.7.2.3 Cost estimates

VENCorp's proposal

The project cost estimates included in both VENCorp's initial and revised forecast planned augmentation expenditure come from two sources:

- cost estimates requested from SP AusNet for planning purposes. The cost estimates provided by SP AusNet are presented with a variance of ±25%. VENCorp states that it subjects those estimates provided by SP AusNet to due diligence where possible by comparing them to the cost of recently completed projects of a similar nature[126]
- VENCorp's own estimates based on its past experience.

VENCorp states that it would be an inefficient use of both VENCorp's and SP AusNet's resources to further refine the cost estimates at this stage.[127]

In reconciling its initial proposal with its 2007 EAPR, VENCorp revised many of the forecast project costs included in its initial proposal.

The revised cost estimates included in VENCorp's revised proposal come from the following two sources:

- the revised cost estimates provided by SP AusNet to VENCorp as part of its EAPR process
- "rule of thumb" cost extrapolations developed by VENCorp for the purposes of its 2007 EAPR and included in its revised revenue proposal.

These are considered in turn below.

The AER notes that the revised cost estimates presented in VENCorp's reconciliation of the 2007 EAPR with its initial revenue proposal no longer include the +25% cost multiplier applied to all projects in its initial proposal. In explaining its election not to apply this adjustment, VENCorp concedes that removal of the multiplier is the most prudent approach to adopt at this stage.[128]

Revised cost estimates provided by SP AusNet

VENCorp states that time constraints mean that it is not feasible to ask SP AusNet to renew all estimates every year. As part of its usual EAPR process VENCorp requested updates for a limited number of cost estimates for potential augmentations.

The six revised cost estimates requested by VENCorp from SP AusNet as part of its 2007 EAPR process were significantly higher than previous estimates for the same projects. SP AusNet informed VENCorp[129] that it had significantly altered its approach to calculating the estimates, by shifting from a 'greenfield' approach to a more sophisticated 'brownfield' approach that took account of site specific needs. SP AusNet also states that the previous cost estimates were based on outdated cost

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[126] VENCorp, *op cit*, p. 31
[127] VENCorp, email to PB, 11 May 2007.
[128] VENCorp, email 19 July 2007, p.3
[129] SP AusNet, email to VENCorp, 25 May 2007.

data from 2000 to 2004.[130] SP AusNet provides two reasons for the significant jump in its cost estimates:

- increases in costs due to the current economic environment and
- more detailed assessments to account for likely brownfield factors in delivery of the works.[131]

VENCorp's "rule of thumb" cost extrapolations

VENCorp applied a "rule of thumb" cost extrapolation to a number of projects not covered by SP AusNet's revised cost estimates. Its rationale for doing this was that it did not want to use "clearly out of date and incorrect estimates".[132]

VENCorp's "rule of thumb" extrapolation divides projects into like categories and applies the average increase in the SP AusNet cost estimates across all projects in the relevant category. The extrapolation factors VENCorp has applied to each category of project are:

- 100% — transformers
- 50% — transmission lines
- 25% — other projects and
- 10% — capacitor banks.[133]

Consultant's review

Revised cost estimates provided by SP AusNet

NC conducted a detailed review of the impact of the revised cost of the fourth transformer at Dederang (see section 4.7.2.4 for details), and concludes that there does not appear to be any reason to believe that the other revised cost estimates provided by SP AusNet and adopted by VENCorp should not be accepted for the particular projects to which they relate. In reaching this conclusion NC comments on the following similarities between the cost estimate reviewed as part of the Dederang project review, and the projects to which the other revised cost estimates apply:

- the costs of these projects in the initial proposal were also based on previous SP AusNet estimates
- three of the projects are transformer projects, similar to the Dederang project, while the fourth is a line upgrade project and
- for the purposes of VENCorp's revenue proposal, all projects have been presented with the same indicative timing (equal distribution of costs across the last four years of the forthcoming period) as the Dederang project.

Through its detailed review of the fourth transformer at Dederang project, and guided by the above observations regarding the other projects for which SP AusNet provided revised cost estimates, NC found no reason to believe that the other revised cost

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[130] SP AusNet, email to VENCorp, 25 May 2007.
[131] SP AusNet, email to VENCorp, 25 May 2007.
[132] VENCorp, email to AER, 3 August 2007.
[133] VENCorp, *Network augmentation cost estimates increases spreadsheet* (VENCDOCS-218386-v1-Cost estimates as prepared for AER.xls), received 3 August 2007.

estimates provided by SP AusNet were developed on a different basis to that accepted in relation to the Dederang project. Therefore, NC considers that it is reasonable to accept that there is a valid case for the increase in the costs of those projects for which SP AusNet has provided revised estimates. However, NC considers that it is necessary to adjust the cost estimates to take into account the forecast reduction in real costs towards the end of the next period.[134] NC has divided each project into its main components (eg transformers, substation and line components), and applied individual cost escalators to each component. The methodology used by NC to make this adjustment is consistent with that adopted by the AER in its draft decision on SP AusNet.

VENCorp's "rule of thumb" cost extrapolations

NC reviewed two of the projects to which VENCorp has applied its "rule of thumb" extrapolation. The initial costing of the forecast general allowance for minium reactive support in the state grid area was based on an internal VENCorp estimate. NC therefore concludes that much of the basis presented for the extrapolation of SP AusNet revised cost estimates is in this instance not valid.[135] For the fourth Loy Yang to Hazelwood line project, the original costing in VENCorp's forecast was based on an earlier estimate from SP AusNet, but NC has disagreed with the inclusion of the 50% "rule of thumb" extrapolation factor. Based on its findings in relation to these detailed reviews, and its assessment of the methodology used to derive the "rule of thumb" escalators, NC considers that VENCorp's "rule of thumb" extrapolations are not an appropriate methodology by which to escalate the costs of forecast planned augmentations. NC recommends the removal of the rule of thumb extrapolation from all the projects to which it has been applied.

NC does, however, consider it appropriate to apply some form of escalator to the forecast planned augmentation costs in VENCorp's revised revenue proposal, as VENCorp's cost estimates are 'point in time' estimates, and do not attempt to take into account any movement in costs between the base year and the indicative timing forecast by VENCorp. NC has also recommended the application of a brownfield escalation factor to certain projects as the older SP AusNet estimates were developed on a greenfield basis. NC has applied an escalation factor which represents an efficient cost for each project, taking into account VENCorp's forecast indicative timing and brownfield considerations. The escalation data used by NC is consistent with that applied by the AER in its draft decision on SP AusNet.

AER's considerations

Cost estimates are a key input into a revenue proposal and are important to the AER's assessment of whether the forecast expenditure reasonably reflects a realistic expectation of the cost inputs required to meet the objectives under the NER in the forthcoming regulatory period. The AER notes PB's suggestion that VENCorp's dependence on the cost estimates provided by SP AusNet may limit its understanding of up to date market conditions for relevant inputs, and that further advice from third parties may be more efficient, and would assist in VENCorp's planning process.[136]

[134] Nuttall Consulting, *op cit*, p. 42.
[135] ibid, p. 44
[136] PB Strategic Consulting, *op cit*, p. 114

VENCorp has only been able to provide the AER and its consultants with limited evidence that it assesses the reasonableness of the cost estimates provided by SP AusNet. VENCorp has informed the AER that none of the cost estimates used in its EAPR process, and therefore its revenue proposal, have been subject to third party review. Further, the cost estimates are usually presented to VENCorp only as a total capital cost of the project, preventing VENCorp from assessing the line-by-line build up of the costs.

During the review process the AER and PB sought clarification from VENCorp regarding the methodology SP AusNet used to calculate the cost estimates, as it was unclear what costs SP AusNet was including in the cost estimates.

From the information available, it appears that the new brownfield approach adopted by SP AusNet is more rigorous, and should therefore be a more accurate estimate of actual costs. The AER notes that the limited number of estimates provided by SP AusNet using this new approach have all significantly increased from the previous estimates for the same projects.[137]

Despite the more rigorous analysis undertaken by SP AusNet in developing the cost estimates, the AER does not accept the project costs contained in VENCorp's forecast planned augmentation expenditure. The AER's analysis of the revised cost estimates is set out below.

Revised cost estimates provided by SP AusNet

The AER accepts NC's recommendation that there is a valid case to allow the increase in costs in projects that have been subject to the revised cost estimates from SP AusNet. The AER also accepts NC's escalation of those estimates to account for VENCorp's forecast timing of each project, and brownfield factors where appropriate. The AER notes that the escalation data and methodology used by NC to escalate these costs are those used in the AER's draft decision on SP AusNet. The AER considers that this is an appropriate basis for escalating VENCorp's forecast planned augmentation costs.

[137] See section 4.7.2.3 for Nuttall Consulting's review, and the AER's considerations of the revised estimates.

Table 4.10 AER's draft decision — Adjustments to projects using SP AusNet revised cost estimates

Project	Initial proposal	Revised proposal	NC's recommendation	AER's draft decision
4th 330/220 kV transformer at Dederang*	13.8	21.0	19	19
Another 500/220 kV transformer at Hazelwood[1]	22.0	40.0	36.2	36.2
3rd 700 MVA 330/220 kV transformer at South Morang	20.0	28.0	25.5	25.2
Phase angle transformer on 220 kV Bendigo to Shepparton line	5.0	23.0	20.6	20.6
220 kV line uprate to 70deg Eildon to Thomastown	2.4	21	4.9	4.9

Source: Nuttall Consulting, p.42, and 64 and AER analysis.
* Note that this project has been the subject of a detailed project review as part of the AER's assessment of VENCorp's forecast planned augmentation expenditure, and the figure in this table does not represent the AER's final conclusion on the efficient level of expenditure for this project which is discussed in section 4.7.2.4 below.

VENCorp's "rule of thumb" cost extrapolations

The AER accepts NC's recommendation that VENCorp's "rule of thumb" extrapolations should be rejected. The methodology by which VENCorp developed and applied the "rule of thumb" is overly simplistic in its assumptions, and is likely to produce an unrealistic expectation of project costs. The AER accepts NC's finding that there is a basis for applying some form of cost escalation, and considers that the application of escalation factors consistent with the AER's approach in its draft decision on SP AusNet is an appropriate basis for escalating the project cost estimates that make up VENCorp's forecast of planned augmentation expenditure.\

Table 4.11 AER's draft decision — Adjustments to projects using VENCorp's "rule of thumb" extrapolations ($m, 2007–08)

Project	Initial proposal	Revised proposal	NC's recommendations	AER's draft decision by project
Reactive support*				
Load driven				
Minimum reactive support in state grid	8	7.5	7	**7**
Minimum reactive support in met area	20	3.5	3.2	**3.2**
Generation driven				
Additional reactive support in met area	20 / 0	16 / 1.5	14.8/1.4	**14.8/1.4**
Additional reactive support in state grid	4	5	4.6	**4.6**
SVCs in State grid				
Load driven	20	28	23.2	**23.2**
Generation driven	20	28	23.2	**23.2**
Wind monitoring projects – all load driven				
220 kV Eildon to Thomastown	0.7	0.8	0.7	**0.7**
220 kV Rowville to Richmond	0.5	0.6	0.5	**0.5**
220 kV Rowville to Malvern	0.4	0.5	0.4	**0.4**
220 kV Springvale to Heatherton	0.4	0.5	0.4	**0.4**
220 kV line uprates 82deg Rowville – Springvale	1	1.5	1.3	**1.3**
Terminal Station works				
upgrade Moorabool and Geelong	1	1.3	1	**1**
upgrade terminations at Hazelwood	6	7.5	6	**6**
New 500 kV terminal station at Mortlake	12	15	14.2	**14.2**
Series compensation and shunt capacitor bank Wodonga/Dederang	12	15	15	**15**
330 kV line uprate South Morang to Dederang and line compensation	7.4	10	9.2	**9.2**
Series compensation on 220 kV line Eildon to Thomastown	7	9	9.2	**9.2**
4th 500 kV Loy Yang to Hazelwood*	30	45	37.7	**37.7**

Source: Nuttall Consulting, p.45, and AER analysis.

* Note that these projects have been subject to further review as part of the AER's assessment of VENCorp's forecast planned augmentation expenditure, and the figures in this table do not represent the AER's final conclusion on the efficient

level of expenditure for these projects, which is discussed in sections 4.7.2.4 and 4.7.2.5 below.

Table 4.12 shows the AER's total adjustment due to the removal of VENCorp's "rule of thumb" cost extrapolations, and the application of appropriate cost escalations.

Table 4.12 AER's draft decision — Adjustments due to the removal of VENCorp's "rule of thumb" extrapolations

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Total
NC's recommendations	–	-0.3	-0.8	-5.8	-0.8	-1.4	-9.1
AER's draft decision	–	-0.3	-0.56	-5.34	-0.56	-1.18	-7.93

Source: Nuttall Consulting, p.56 and AER analysis.

4.7.2.4 Detailed review of selected forecast planned augmentation projects

The AER and its consultants undertook detailed reviews of several of VENCorp's forecast projects with a view to ascertaining the efficiency and prudency of each project, and determining whether there are any systemic issues that may be prevalent throughout the forecast planned augmentation expenditure. This section provides a summary of PB's recommendations and the AER's conclusions on the detailed project reviews undertaken by PB on a sample of VENCorp's forecast planned augmentation projects. The details of PB's project reviews and the AER's analysis are set out below.

PB conducted detailed reviews of five forecast planned network augmentation projects. Projects were selected in consultation with the AER, with regard to the following factors:

- *Materiality:* the cost associated with the project and the proportion of the total forecast it comprises. Both small and large value projects have been selected to ensure VENCorp treats small projects with the same diligence as large projects.
- *Project/Asset category:* a comprehensive selection of projects across each of the classifications adopted (by project type or asset class) ensures detailed project reviews capture the key processes and systems employed by VENCorp.
- *Project location and affected parties:* the project location (i.e. rural or metropolitan), and the participants affected (i.e. generators, customers, DNSPs and other TNSPs) can each provide insight into VENCorp's practices and processes.
- *Timing of the expenditure:* ensures changes in processes and systems can be identified across the entire forecast expenditure period. The drivers for any changes identified need to be understood to ensure prudent decision making processes have been adopted.

VENCorp's proposed planned augmentation forecast is built on the basis of a series of line items, which fall into two basic categories:

- projects with a specified scope of works — account for approximately 75% of VENCorp's forecast planned augmentation expenditure (eg Fifth 500/220 kV transformer at Hazelwood, Fourth 500 kV line Loy Yang to Hazelwood) and
- 'general allowances' of undefined scope — the remaining 25% ($70.6m) of VENCorp's forecast planned augmentation expenditure is comprised of three sets of general allowances, for which no particular need or timing is identified. These are more akin to 'undefined works allowances' than projects, and include:
  - Minimum reactive support in the Metropolitan and State Grid areas
  - Line terminations and monitoring equipment in the Metropolitan and State Grid areas and
  - Minimum fault limiting devices in the Metropolitan area.

For three of the projects selected for detailed review, VENCorp has presented a defined purpose, scope and timing. However, VENCorp's forecasts of expenditure on reactive support in the state grid area and line terminations and monitoring equipment in the metropolitan area are general allowances.

Table 4.13 Forecast planned augmentation projects subject to detailed review

	Project category	**Project reviewed**	**Project expenditure ($m, 2007–08)**	**Total forecast planned augmentation expenditure reviewed (%)**
General allowances	Load driven	Reactive support in the state grid area	10	2.8
	Load driven	Line terminations and monitoring equipment in the metropolitan area	19	5.3
Defined projects	Load driven	1000MVA 500/220 kV transformer in the metropolitan area	43.8	12.4
	Generation driven	Fourth 330/220 kV transformer at Dederang	13.8	3.9*
	Generation driven	Fourth 500 kV line from Loy Yang to Hazelwood	37.5	5.3*
Total			**124.1**	**29.7**

Source: PB Strategic Consulting, p.63.
* Percentage based on weighted expenditure.

Due to the timing of the release of the 2007 EAPR, PB was unable to assess what impact, if any, the reconciliation of the 2007 EAPR and the initial proposal would have on its recommendations to the AER. As such, the AER engaged NC to undertake this work.

NC assessed whether or not the revised proposal and the 2007 EAPR had a material impact on PB's recommendations regarding the efficiency and prudency of the projects reviewed. NC's findings are presented in brief below, along with the AER's consideration of the recommendations. The AER's consideration of NC's recommendations is set out in more detail in appendix A.

Reactive support in the state grid area

PB concludes that VENCorp has not demonstrated the need for the proposed non-specific, general allowance in VENCorp's forecast for minimum reactive support in the state grid area. VENCorp did not provide any technical studies to support its proposal in relation to need or timing. Further, PB concludes that VENCorp has not presented a coordinated and systematic business case to demonstrate how other forecast augmentation projects may offset the need for reactive support in the state grid area.[138] PB recommended that the AER approve an adjusted allowance of $2.3m for one shunt capacitor in the state grid area, in the final year of the forthcoming regulatory period

Since its initial proposal, VENCorp has undertaken further analysis on its reactive support requirements in the state grid area. NC found no evidence that this new analysis is substantially different from that underpinning the original proposal, and therefore concludes that none of the new information presented had a material impact on PB's conclusion. In its revised proposal VENCorp has applied a "rule of thumb" cost extrapolation of 10% to the original cost of a 2 x 25 MVAr switched capacitor bank applied in calculating the amount of the general allowance, taking the per unit cost from $2.3m to $2.5m. In rejecting this extrapolator NC notes that the original cost estimate was based on actual contract costs from recent contestable projects.[139] However to account for forecast real changes in price, NC has applied an escalation factor of 1.9%, based on the escalation data the AER applied in its draft decision on SP AusNet. NC's recommendation is therefore to allow $2.34m for reactive support in the state grid area over the forthcoming regulatory period.[140]

The AER accepts PB's recommendation to include a reduced allowance for one shunt capacitor in the state grid area in the final year of the forthcoming regulatory period, and does not consider that the forecast general allowance reasonably reflects a realistic expectation of the cost inputs that VENCorp will require to meet the capex objectives in the forthcoming regulatory period. The AER notes that VENCorp has not presented any technical studies or supporting evidence that indicates a need for the general allowance it seeks. Nor has it undertaken adequate analysis of the interaction with several other projects which may impact on the need and timing of this expenditure. This is particularly relevant given the displacement, in the current regulatory period, of reactive support works for which a comparable allowance was approved by the ACCC in its 2002 decision. The AER sees no basis for the 10% "rule of thumb" escalation used by VENCorp, and has instead applied NC's escalation,

[138] PB Strategic Consulting, *op cit*, p.74
[139] VENCorp, *Network augmentation cost estimates increases spreadsheet* (VENC DOCS-218386-v1-Cost_estimates- as prepared for AER.xls), received 3 August 2007, which indicates that the basis of the unit cost estimate is December 2006.
[140] Nuttall Consulting, *op cit,* p. 22

which is based on the cost escalation data used by the AER in its draft decision on SP AusNet. The resultant adjusted allowance is $2.34m.

Line terminations and monitoring equipment in the metropolitan area

PB comments that there is a lack of detailed technical studies to support VENCorp's forecast general allowance for line terminations and monitoring equipment in the metropolitan area. PB concludes that it is likely that VENCorp has materially overstated its expenditure requirements in relation to this allowance.[141] PB also found a lack of evidence that VENCorp has considered the impact of SP AusNet's forecast capital works on the need for this allowance, and recommended a 50% reduction in the forecast allowance to make it reflective of past expenditure of this nature.[142]

The only change to this general allowance in VENCorp's revised proposal is the removal of the +25% cost multiplier, reducing the amount of the forecast allowance from $19m to $15m. NC concludes that neither the revised proposal nor the 2007 EAPR have had a material impact on PB's recommendation to allow $9.5m (a reduction of 50% from the initial forecast) for line termination and monitoring equipment in the metropolitan area. NC comments that no new information has been provided on this general allowance.

The AER agrees with PB's finding that VENCorp's historical expenditure patterns and PB's experience suggest that piecemeal upgrades of limiting plant — as contemplated by this general allowance — can be efficient. In the absence of information supporting the forecast allowance put forward by VENCorp, the AER is not satisfied that it reasonably reflects a realistic expectation of the cost inputs that VENCorp will require to meet the capex objectives in the forthcoming regulatory period. The AER has therefore reduced the forecast allowance by 50% to a level that is reflective of past expenditure in this area. In reaching this conclusion, the AER accepts NC's finding that neither the revised proposal, nor the 2007 EAPR have a material impact on PB's recommendations on this allowance.

1000MVA 500/220 kV transformer in the metropolitan area

PB was satisfied that, once the +25% cost multiplier was removed, the estimated cost of this project put forward by VENCorp in its initial proposal ($35m) was reasonable and efficient.

However, PB considered that the timing forecast by VENCorp for the new metropolitan transformer project in its revenue proposal (2012–13) was not prudent, and that it was likely that the actual timing of the project would fall outside the forthcoming regulatory period.[143] PB therefore recommends that no allowance be made for this project. In support of its conclusions in relation to the forecast timing, PB found:

- The load-flow cases used by VENCorp to model summer 2013–14 are more reflective of the 10% PoE forecast conditions in *2014–15*, implying that the timing of the project is advanced.

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[141] PB Strategic Consulting, *op cit,* p. 77
[142] ibid., p. 77
[143] ibid., p. 70

- The 10% PoE forecast used is materially higher than the 50% PoE conditions, under which the timing may in fact be deferred by as much as five years from that indicated by the 10% PoE.
- While acknowledging that the load flows are relatively insensitive to the location of new generation, the Latrobe Valley scenario used by VENCorp in this instance is the worst case of the four scenarios.[144]

PB also noted the lack of scoping and documentation provided by VENCorp to justify the underlying need for the project.

NC notes that the only change to the project from the initial proposal is that VENCorp has deferred its forecast timing from 2012–13 to 2013–14. NC found that the revised proposal and the 2007 EAPR did not have a material impact on PB's recommendation not to provide an allowance for the 1000MVA 500/220 kV transformer in the metropolitan area allowance. The deferred timing is in line with the 2007 EAPR which states that the timing of the project will be approximately 2014,[145] and strengthens PB's conclusion that the timing of the project in the initial proposal was advanced, and that it is likely to proceed outside the forthcoming regulatory period.

The AER agrees with PB's recommendation not to provide any allowance for the new metropolitan transformer project, and accepts NC's conclusion that the revised proposal and 2007 EAPR did not have a material impact on PB's conclusion. The AER is not satisfied that the project will be required to meet expected demand over the forthcoming regulatory period, or that it is in fact likely to proceed in that period when VENCorp's own planning criteria and decision-making processes are taken into account.146 In drawing this conclusion, the AER accepts PB's view that the timing forecast by VENCorp for the purposes of its revenue proposal is not a reasonable reflection of an indicative probabilistic approach and does not align with VENCorp's own planning criteria.[147]

Fourth 330/220 kV transformer at Dederang

PB concludes that VENCorp has not identified a clear need for the installation of the fourth transformer at Dederang. In particular, PB notes that VENCorp has not demonstrated if or how it has considered the option of augmenting the existing third transformer put forward by SP AusNet in its revenue proposal for the same regulatory period, in identifying its preferred project scope. PB concludes that the efficient outcome is the replacement of the third transformer, and does not believe that the installation of a fourth transformer is necessary during the forthcoming regulatory period. To facilitate this outcome, PB recommends that 50% of the cost of the replacement of the third transformer be given to VENCorp, and 50% given to SP AusNet, and that the two businesses should prepare a coordinated business case that captures both the augmentation benefit and reduction in asset failure risk.

[144] ibid., p. 70
[145] VENCorp, 2007 EAPR, p.73
[146] NER cl. 6A.6.7(a)(1).
[147] PB Strategic Consulting, *op cit*, p.71

VENCorp's revised proposal made significant changes to the fourth transformer at Dederang project. Where it originally appeared in all four generation scenarios, it now appears only in the Snowy/NSW import scenario.[148] The estimated cost of the project has increased from $13.8m to $21m on the basis of a revised cost estimate provided to VENCorp by SP AusNet. The revised proposal also includes a minor scope change involving a double switched 330 kV bay.

NC has undertaken a detailed analysis of the basis for the significant increase in the cost estimate received from SP AusNet.[149] NC concludes that the original estimate of $13.8m ($11m excluding the +25% cost multiplier) was too low, and that the revised estimate of $21m, on which VENCorp now bases its forecast, is reasonable. NC has accepted the basis for VENCorp's revised cost estimate, but has adjusted it to take into account VENCorp's forecast timing of the project, as the SP AusNet cost estimates provided to VENCorp do not take into account the actual year (or range of years) in which VENCorp has forecast the project to occur. NC also concludes that there is no basis for the change in scope contained in the revised proposal, and notes that neither VENCorp nor SP AusNet (in its cost estimate) have provided any comment on the change. [150] NC therefore concludes that the revised proposal and the 2007 EAPR do not materially impact on PB's recommendation to the AER that it would not be prudent and efficient to undertake this project over the forthcoming period.[151]

The AER accepts PB's recommendation that the forecast installation of a fourth transformer is not required to meet expected demand over the forthcoming regulatory period. The AER notes that PB, in its report, *SP AusNet revenue reset, an independent review*, concludes that on a 'replacement only' basis there is no justification for SP AusNet's proposed replacement of the third transformer.[152] However, when viewed holistically, PB concludes that the need for the replacement can be justified when considering the augmentation requirements. Therefore the AER proposes to allow VENCorp $2.48m, which represents SP AusNet's forecast cost of augmenting the network by replacing the third transformer with a larger unit, weighted according to VENCorp's generation scenarios. The AER accepts NC's conclusion that the revised proposal and the 2007 EAPR do not materially impact on PB's recommendations.[153]

Fourth 500 kV line from Loy Yang to Hazelwood

PB considers that VENCorp has presented a clear need for the fourth 500 kV line from Loy Yang to Hazelwood in the two scenarios in which it is forecast to occur. Although VENCorp has not yet estimated the timing of the implementation of the project with any precision, PB believes that the assumed distribution of forecast costs across the last four years of the forthcoming regulatory period is appropriate. With respect to the project scope, PB recommends that the efficient scope involves the

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[148] The AER was advised prior to the reconciliation that VENCorp believed that the inclusion of this project in all four scenarios was in error.
[149] Nuttall Consulting, *op cit*, p.26–32
[150] ibid., p. 30
[151] ibid., p. 31
[152] PB Strategic Consulting, *SP AusNet revenue reset, an independent review*, p. 98
[153] Nuttall Consulting, *op cit*, p. 31

single switching of the line at both ends, rather than the double switching proposed by VENCorp. PB states that this would represent a saving in the order of $2m without any material reduction in the functional and operational performance of the assets.[154]

In its revised proposal:

- VENCorp has applied a “rule of thumb” cost extrapolation of 50% to the initial forecast cost, based on another cost estimate received from SP AusNet. This extrapolation produced a revised forecast cost of $45m, an increase of $8.5m from the initial proposal, despite the removal of the +25% cost multiplier
- VENCorp only includes the project in the Latrobe Valley generation scenario, whereas in the initial proposal, the project fell into two scenarios.

Based on the above changes, NC concludes that the revised proposal does have a material impact on PB’s findings. NC agrees with the appropriateness of the revision made by VENCorp in its revised proposal to remove the Loy Yang to Hazelwood project from the Snowy/NSW import scenario due to the increase in cost,[155] but does not accept VENCorp’s “rule of thumb” cost extrapolation. NC does, however, see the need to escalate the cost and has done so in a manner which is consistent with the AER’s draft decision on SP AusNet. The resultant revised estimate for this project is $35.74m.

The AER accepts NC’s conclusion that the revised proposal had a material impact on PB’s recommendations. The AER notes that VENCorp removed the project from the import scenario, and agrees with NC’s conclusion that this change is warranted given the increase in cost of the project from the initial proposal. The AER accepts NC’s conclusion that PB’s recommendation in relation to the efficient scope of the project has not been materially affected by the revised proposal. The AER therefore accepts PB’s recommendation to change the scope of the project from double to single switching, which represents a reduction of $2m. The AER accepts NC’s recommendation that the appropriateness of the 50% “rule of thumb” escalator has not been demonstrated, but agrees with NC’s view that there is a need to escalate the project cost to reflect the forecast timing of the project. On that basis the AER accepts that NC’s recommended cost of $37.7m reasonably reflects a realistic expectation of the cost inputs associated with this project. As this project falls into only one scenario, this translates into a weighted allowance of $8.94m (25%), to be included in VENCorp’s forecast planned augmentation expenditure.

Impact of revised load forecast contained in the 2007 EAPR

NC was asked to review what impact, if any, the revised load forecast contained in the 2007 EAPR may have on PB’s recommendations to the AER in relation to forecast planned augmentation expenditure. As noted above, due to the timing of the publication of the 2007 EAPR, VENCorp has not updated its revenue proposal to take this new information into account. This is consistent with VENCorp’s planning approach, as for planning purposes VENCorp has used the load forecast published in the 2006 EAPR in its 2007 EAPR.

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[154] PB Strategic Consulting, *op cit*, p. 85
[155] Nuttall Consulting, *op cit*, p. 37

In relation to the five projects subject to a detailed project review by PB, NC concludes that the impact of the 2007 EAPR load forecast will be to defer the likely timing of four of the five projects. In relation to the fourth transformer at Dederang project, NC considers that the reduction in forecast load growth will have little impact on the need.[156]

The 2007 EAPR load forecast is lower than that contained in VENCorp's revenue proposal and its 2006 EAPR. The AER notes the timing of the publication of the 2007 EAPR, and recognises the practical difficulties surrounding the application of the most recent forecasts to VENCorp's revenue proposal. However, the AER accepts NC's view that the lower maximum demand contained in the 2007 EAPR load forecast — and the ensuing reduction in additional generation required in VENCorp's generation scenarios — will result in a deferral of augmentation needs over the forthcoming regulatory period. Therefore the AER considers that the 2007 EAPR load forecast strengthens the basis for those reductions it has made to VENCorp's forecast planned augmentation expenditure.

AER's conclusions on detailed project reviews

On the basis of these detailed reviews, the AER has made a downward adjustment of $50.7m to VENCorp's revised forecast planned augmentation expenditure.

Table 4.14 below shows PB's recommendation on the detailed project reviews; NC's recommendations on the impact of VENCorp's revised proposal and the 2007 EAPR on these projects reviews; and the AER conclusions in relation to these project reviews.

[156] Nuttall Consulting, *op cit*, p. 52

Table 4.14 AER's draft decision — detailed project reviews ($m, 2007–08)

		2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Load driven projects								
1000MVA 500/220 kV transformer in the metropolitan area	Initial proposal	–	–	–	–	43.8	–	43.8
	PB's recommendation	–	–	–	–	–	–	–
	Revised proposal	–	–	–	–	–	35.0	35.0
	NC's recommendation	–	–	–	–	–	–	–
	AER draft decision	–	–	–	–	–	–	–
Reactive support in the state grid area	Initial proposal	–	–	2.5	2.5	2.5	2.5	10.0
	PB's recommendation	–	–	–	–	–	2.0	2.0
	Revised proposal	–	–	2.5	2.5	–	2.5	7.5
	NC's recommendation	–	–	–	–	–	2.34	2.34
	AER draft decision	–	–	–	–	–	2.34	2.34
Line terminations and monitoring equipment in the metro area	Initial proposal	–	3.8	3.8	3.8	3.8	3.8	19.0
	PB's recommendation	–	1.9	1.9	1.9	1.9	1.9	9.5
	Revised proposal	–	3.0	3.0	3.0	3.0	3.0	15.0
	NC's recommendation	–	1.9	1.9	1.9	1.9	1.9	9.5
	AER draft decision	–	1.9	1.9	1.9	1.9	1.9	9.5

		2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Generation driven projects								
Fourth 330/220 kV transformer at Dederang	Initial proposal	–	–	3.45	3.45	3.45	3.45	13.8
	PB's recommendation	–	–	–	–	5.0	–	5.0
	Revised proposal	–	–	1.31	1.31	1.31	1.31	5.25
	NC's recommendation	–	–	–	–	5.0		5.0
	AER draft decision	–	–	0.62	0.62	0.62	0.62	2.48
Fourth 500 kV line from Loy Yang to Hazelwood	Initial proposal	–	–	4.69	4.69	4.69	4.69	18.75
	PB's recommendation	–	–	3.50	3.50	3.50	3.50	14.00
	Revised proposal	–	–	2.81	2.81	2.81	2.81	11.25
	NC's recommendation	–	–	2.23	2.23	2.23	2.23	8.94
	AER dradt decision	–	–	2.23	2.23	2.23	2.23	8.94
Total	**Initial proposal**	**–**	**3.8**	**14.44**	**14.44**	**58.24**	**14.44**	**105.35**
	PB's recommendation	**–**	**1.90**	**5.40**	**5.40**	**10.40**	**7.40**	**30.50**
	Revised proposal	**–**	**3.00**	**9.63**	**9.63**	**7.13**	**44.63**	**74.00**
	NC's recommendation	**–**	**1.9**	**4.13**	**4.13**	**9.13**	**6.48**	**25.78**
	AER's draft decision	**–**	**1.9**	**4.75**	**4.75**	**4.75**	**7.10**	**23.26**

Source: NC, pp.18–38, AER analysis.

4.7.2.5 Extension of findings to remainder of forecast planned augmentation expenditure

The purpose of the detailed project reviews set out in section 4.7.2.4 was to inform the AER's assessment of VENCorp's total forecast augmentation expenditure. On the basis of its detailed project reviews, PB drew a number of conclusions in relation to the total forecast of planned augmentation expenditure in VENCorp's proposal. This section sets out the AER's consideration of the implications of the detailed project reviews for other areas of VENCorp's forecast expenditure.

PB's recommended extrapolation

PB identified several issues that indicated that its findings could be extrapolated over a wider section of VENCorp's forecast expenditure, and makes the following comments in support of a further reduction to VENCorp's total forecast planned augmentation expenditure:

- VENCorp's forecast planned augmentation expenditure appears quite aggressive when compared with its actual expenditure over the 2003–08 regulatory period, indicating that the efficiency in investment is considerably reducing.
- The inclusion of the Malvern to Heatherton cable project at an indicative cost of $43.8m[157] contradicts the finding in the 2006 EAPR which concludes that VENCorp's analysis has not identified any option that technically and economically alleviates the constraint at this time.[158]
- There appear to be several load driven, "must do", projects that should be more appropriately considered as generation scenario specific.
- There are several generation scenario dependent projects that are included in scenarios that appear counter-intuitive. PB is of the opinion that following detailed reviews, the amount of scenarios some projects appear in could be reduced.[159]

Having concluded that VENCorp's forecast planned augmentation expenditure significantly overstates the prudent and efficient costs of planning and augmenting the network in the forthcoming regulatory period, and the level of expenditure that will likely be required in that period, PB recommends a high level adjustment to VENCorp's forecast planned augmentation expenditure.

PB suggests that the determination of the efficient level of forecast planned augmentation expenditure should be informed by VENCorp's past level of efficient expenditure (as supported by PB's review of committed augmentation expenditure). PB therefore proposes that the efficient augmentation expenditure to demand growth ratio is $0.15m/MW, as opposed to the equivalent ratio of $0.3m/MW reflected in VENCorp's proposal.[160] PB's analysis of VENCorp's augmentation expenditure over the current regulatory period indicates that its forecast expenditure for the forthcoming period is three times less efficient that its expenditure over the current period.[161] In relation to this proposed increase in expenditure per MW of load growth, PB observes:

> This appears to be a considerable change in the capex requirements that is not directly supported by the generalised (non-specific), and to some extent un-substantiated, nature of the forecast capex and the detailed projects reviewed.

[157] The cost of this project has been reduced to $25m in VENCorp's revised proposal. The AER notes that this is inconsistent with the 2007 EAPR which states that the project has an estimated cost of $53m.

[158] VENCorp, *2006 EAPR*, p.69. The 2007 EAPR does not provide any further analysis on this project but does state that VENCorp is undertaking joint analysis with affected parties (p.69).

[159] PB, *op cit*, p.92

[160] These figures assume the 10% PoE forecast demand growth, consistent with VENCorp's methodology.

[161] These figures have been calculated by PB using the ratio of the 6 year increase in 10% PoE peak summer demand growth over forecast expenditure for the current and forthcoming period (PB Strategic consulting, VENCorp revenue reset, an independent review, p.88).

The result of PB's high level adjustment to VENCorp's forecast planned augmentation expenditure is a revised planned augmentation expenditure forecast of $180.4m. Having reviewed the information provided by VENCorp following the release of its 2007 EAPR, NC comments that:

> The 2007 EAPR load forecast may give the AER greater confidence that such a benchmark may represent the prudent and efficient expenditure for planned augmentation.[162]

AER's considerations

The AER accepts that several of the issues that have been identified during the review process are indicative of broader issues likely to recur throughout VENCorp's forecast of planned augmentation expenditure. On the basis of PB's findings, and in light of NC's conclusion that the revisions to VENCorp's forecast planned augmentation expenditure following the release of the 2007 EAPR do not materially impact on those findings, the AER is not satisfied that VENCorp's initial or revised forecasts reasonably reflect the prudent and efficient costs of meeting the objectives defined in the NER, or a realistic expectation of the cost inputs required to do so.

The AER has considered PB's proposed approach to determining a revised forecast of expenditure for the purposes of the AER's draft decision. While the AER accepts PB's conclusion that further investigation of VENCorp's proposal is likely to reveal similar issues to those identified by PB in its detailed project reviews, the AER notes that:

- PB's methodology assumes an equal dollar amount of expenditure in response to MW load growth, regardless of what measures are taken to address the resultant constraints. In practice, this assumption is unlikely to hold.
- PB's methodology assumes that levels of 'redundancy' in the transmission system are constant. Again, this assumption is unlikely to hold.
- PB's methodology does not base its recommended forecast on VENCorp's proposal, or PB's own recommended adjustments from its detailed project analysis, relying instead on broader comparisons between forecast allowances and load growth for the current and forthcoming regulatory periods.

For these reasons, the AER is reluctant to apply an adjustment calculated in the manner recommended by PB.

AER's extrapolation of findings of detailed project reviews

While rejecting its proposed treatment, the AER accepts PB's conclusion that there are issues identified by PB's review that are likely to be prevalent in other areas of VENCorp's forecast planned augmentation expenditure. On this basis the AER is not satisfied that VENCorp's forecast expenditure can be said to reasonably reflect the criterion established in the NER.

[162] Nuttall Consulting, *op cit*, p. 54

Rather than adopting PB's 'across the board' adjustment, the AER has applied a more targeted extrapolation of those particular findings which PB has stated are likely to be prevalent across like projects,

As noted previously, VENCorp's proposed planned augmentation forecast is built on the basis of a series of line items, which fall into two basic categories:

- projects with a specified scope of works which account for approximately 75% of VENCorp's forecast planned augmentation expenditure, (eg Fifth 500/220 kV transformer at Hazelwood, Fourth 500 kV line Loy Yang to Hazelwood) and
- 'general allowances' of undefined scope, which make up the remaining 25% of VENCorp's forecast planned augmentation expenditure These include three sets of general allowances, for which no particular need or timing has been identified:
    - Minimum reactive support in the Metropolitan and State Grid areas
    - Line terminations and monitoring equipment in the Metropolitan and State Grid areas and
    - Minimum fault limiting devices in the Metropolitan area.

The two 'general allowances' that PB reviewed (see section 4.7.2.4 above) make up around 30% of the total forecast expenditure in the 'general allowance' category, and approximately 8% of VENCorp's total forecast planned augmentation expenditure. PB's findings in relation to the two allowances specifically reviewed are summarised below.

- *Reactive support in the state grid:* PB found that no clear need had been identified for this general allowance, as VENCorp had not referred to any specific outages or pending limitations. PB considered this to be a material issue given the high number of expenditure forecasts that appeared to be based on the same approach, indicating that its findings could be related back to other similar allowances.
- *Line terminations and monitoring equipment in the metropolitan area:* PB concluded that VENCorp appears to have overstated a generalised and non-specific need for this expenditure, and does not appear to have coordinated its requirements with those proposed by SP AusNet. PB is of the view that the amount by which VENCorp has overstated its requirements may be accentuated by the fact that SP AusNet is undertaking substantial works in metropolitan stations in the forthcoming regulatory period. PB considers that its findings could be reflected across all projects for which no clear scope of works has been defined.[163]

The AER's consideration of PB's conclusions on the two general allowances reviewed by PB is set out earlier in this chapter. Having reviewed the treatment of the remaining general allowances in VENCorp's forecast planned augmentation expenditure, the AER accepts PB's suggestion that its findings are likely to be reflected across those general allowances that it has not reviewed in detail. On this basis, the AER is not satisfied that those elements of VENCorp's forecast of planned augmentation expenditure which take the form of general allowances reasonably

[163] PB Strategic Consulting, *op cit*, p. 91

reflect a realistic expectation of the cost inputs that VENCorp will require to meet the capex objectives in the forthcoming regulatory period.

The AER is satisfied that the nature and composition of the remaining allowances in these categories is sufficiently comparable to allow the extrapolation of PB's findings from those allowances that it has reviewed in detail to those that remain. The following section sets out the AER's extrapolation of PB's findings across the relevant components of VENCorp's forecast of planned augmentation expenditure.

The AER asked NC to provide an independent comment on the reasonableness of its conclusions on these matters. The overall finding of NC's review was that the AER's adjustments, which are based on an extrapolation of PB's findings, are appropriate. NC's comments on the individual adjustments are set out in the sections below.

General allowances for minimum reactive support

PB reviewed the forecast general allowance for load driven minimum reactive support in the state grid area and recommended a reduction from $10m to $2m on the basis of historical expenditure.

In reviewing VENCorp's revised proposal, NC found no reason to depart from PB's recommendations. However, on the basis of the revised proposal (which reduced the forecast allowance to $7.5m) and clarification provided by VENCorp, minor adjustments were made to the cost estimates underlying the allowance, resulting in a recommended allowance of $2.34m. This represents a 69% reduction to VENCorp's proposed forecast of $7.5m.

The AER considers that equivalent adjustments should be applied to all general allowances for minimum reactive support to address issues common to the development of these forecasts, and has applied a proportionate, 69% reduction to the four remaining general allowances for minimum reactive support.

NC notes that:

- There is nothing in VENCorp's proposal to suggest that the basis of the other general allowances for reactive support are different to that reviewed by PB, and the form of analysis undertaken by VENCorp to determine the reactive requirements appears to be similar, and
- There is no indication that a coordinated study accounting for other forecast planned projects has occurred with any of the affected allowances.

NC therefore considers it reasonable to assume that some reduction based on PB's findings is appropriate.

NC considers that in the absence of specific information to suggest that the nature of works forecast for the metropolitan as opposed to the state grid area would warrant different treatment, the AER's proportionate adjustment of 69% to other general reactive support allowances is appropriate.

Table 4.15 AER’s draft decision — Minimum reactive support allowances ($m, 2007–08)*

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Total
VENCorp’s revised proposal	–	–	3.03	6.53	3.03	3.03	15.63
AER’s adjustment	–	–	-2.49	-4.91	-2.49	-2.49	-12.4
AER’s draft decision	**–**	**–**	**0.54**	**1.62**	**0.54**	**0.54**	**3.23**

Source: AER analysis.
*Does not include the allowance already reviewed by PB.

General allowances for line termination and monitoring equipment

PB reviewed the general allowance for load driven line termination and monitoring equipment in the metropolitan area, and recommended reducing the allowance from the forecast of $19m in the initial proposal to $9.5m.

VENCorp’s revised proposal reduced the cost estimate for this allowance to $15m. In reviewing VENCorp’s revised proposal, however, NC found no reason to depart from PB’s recommendations. The adjustment from $15m to $9.5m represents a 37% reduction to VENCorp’s proposed $15m allowance.

The AER again considers that proportionate reductions should be applied to all general allowances for line termination and monitoring equipment, and has therefore made corresponding downward adjustments of 37% to the general allowance for line termination and monitoring equipment in the state grid area.

NC provided the following comments:

- There is nothing in VENCorp’s proposal to suggest that the basis of the state grid allowance is different to the allowance for the metropolitan area reviewed by PB, and
- There do not appear to be any supporting planning studies. Importantly there is no indication that VENCorp has adequately accounted for SP AusNet’s redevelopment program for substations in the state grid, which has resulted in a significant upgrade of the state grid substations, including line terminal equipment.

NC therefore considers it reasonable to assume that some reduction based on PB’s findings is appropriate.

NC notes that PB’s adjustment to the general allowance for load driven line termination and monitoring equipment in the metropolitan area was based on historical levels of expenditure. NC considers it reasonable to assume that the proportional (37%) adjustment to the metropolitan allowance is an appropriate proxy for the equivalent adjustment to the state grid allowance.

Table 4.16 AER's draft decision — Line termination and monitoring equipment allowances ($m, 2007–08)*

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Total
VENCorp's revised proposal	–	2	2	2	2	2	10
AER adjustment	–	-0.74	-0.74	-0.74	-0.74	-0.74	-3.7
AER's draft decision	**–**	**1.26**	**1.26**	**1.26**	**1.26**	**1.26**	**6.3**

Source: AER analysis
*Does not include the component of this allowance reviewed by PB.

Minimum fault limiting devices in the metropolitan area

Given the non-prescriptive nature of the proposed allowance, and VENCorp's lack of integration of this allowance with its forecast augmentation projects, the AER considers that it is likely to overstate the efficient level of expenditure in the same way as the other two proposed general allowances, and is therefore unlikely to reasonably reflect a realistic expectation of the costs that VENCorp will need to incur in meeting the capex objectives in the forthcoming regulatory period. This conclusion is supported by PB's comments in relation to those general allowances that were reviewed in detail, and its conclusion that its findings could be extended across all elements of the forecast planned augmentation expenditure for which no scope has been defined.

Given that PB did not make a recommendation specifically on this general allowance, the AER will apply a conservative adjustment to the proposed general allowance for minimum fault limiting devices in the metropolitan area of 37%, being the lower of the two adjustments to the other general allowances made by the AER, based on the relevant findings of PB.

NC notes that the AER's application of the lower, 37% adjustment is in this instance intended to make a reduction that is conservative, rather than to directly link the amount of the forecast allowances for minimum fault limiting devices and line termination and monitoring equipment. Of the two comparable allowances available, NC considers it reasonable to assume that PB's findings on the line terminations allowance may be the most relevant. Noting that both appear to be general allowances without any basis in specific needs, NC considers it reasonable to assume that VENCorp has applied a similar rationale to determine the expenditure allowance for all such items. NC considers it reasonable to assume that the proportional adjustment for the line terminations allowance is an appropriate proxy, and considers the AER's adjustment is appropriate.

Table 4.17 AER's draft decision — Fault limiting devices allowances ($m, 2007–08)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Total
VENCorp's revised proposal	-	3	4.86	4.86	4.86	4.86	22.5
AER's adjustment	-	-1.11	-1.80	-1.80	-1.80	-1.80	-8.33
AER's draft decision	**-**	**1.89**	**3.07**	**3.07**	**3.07**	**3.07**	**14.18**

Source: AER analysis.

The total reduction resulting from the AER's extrapolation of PB's findings across the remaining general allowances is $24.42m. This results in a revised total forecast planned augmentation expenditure of $200.78m.

Table 4.18 AER's draft decision — Total adjustment due to extrapolation of PB's finding ($m, 2007–08)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Total
VENCorp's revised proposal	–	5	9.91	13.41	9.91	9.91	48.13
AER's adjustment	–	-1.85	-5.04	-7.46	-5.04	-5.04	-24.42
AER's draft decision	**–**	**3.15**	**4.87**	**5.95**	**4.87**	**4.87**	**23.70**

Source: VENDOCS #215183, AER analysis.

While materially higher than PB's recommended total forecast planned augmentation expenditure of $180.4m, the AER is reluctant to make the assumptions inherent in PB's proposed overall adjustment. PB's detailed reviews of defined projects suggest that the nature and extent of issues encountered in projects with a defined scope of works are likely to be variable, and the AER does not consider the methodology proposed by PB is an appropriate measure by which to extrapolate those findings across other elements of VENCorp's forecast. The AER's total adjustment to VENCorp's forecast of planned augmentation expenditure is more limited and is likely to be conservative. It may therefore result in a forecast that is on the high side of what might reasonably be expected. On the balance of the information provided, however, the AER is satisfied that the revised total forecast reasonably reflects the capex criteria, with regard to the capex factors.

4.7.2.6 AER's assessment of committed augmentation expenditure

Consultant's review

The AER engaged PB to conduct a review of VENCorp's committed augmentation expenditure in order to better inform its assessment of VENCorp's forecast planned augmentation proposal. In conducting its review, PB had regard to:

- whether a justifiable need for the forecast project was demonstrated by VENCorp
- whether the proposed alternative was the most efficient investment to meet the stated need, and
- whether the proposed alternative was developed, and if not, whether the differences reflect decisions that are consistent with good industry practice.[164]

In all cases examined, PB considered that a justifiable need for the project was identified, and the implemented project costs were reasonable given the nature and scope of the project. Where the relevant documentation was provided, PB also considered that the range of alternatives identified were reasonably comprehensive and practical solutions, and it was reasonably demonstrated that the preferred alternative was the most beneficial of those examined to meet the identified need, and that the preferred alternative was an efficient alternative.

While PB considered that project documentation was, in general, appropriate for the projects examined, it noted that information in relation to the application of demand forecasts and justification of project timing was lacking. In most cases the project implementation timing was demonstrated in the available project documentation to be reasonable, and VENCorp's role in the project's implementation was considered to be consistent with prudent asset management and good industry practice.

PB was satisfied on the balance of the information that was available that VENCorp has complied with its augmentation planning and governance processes. PB notes that it is clear in the majority of projects examined that the overarching principles are based on the requirements of the NER, and guided by the application of the regulatory test to VENCorp's probabilistic planning approach. However, PB also notes that the project documentation provided makes no specific references to VENCorp's strategies, overarching policies or plans.

In concluding, PB notes that overall, while the detailed reviews did identify a number of issues, these essentially relate to the quality of the documentation VENCorp provided as opposed to the project itself. On the balance of the information that was provided, and in the broader context of PB's review, PB concludes that it is likely that VENCorp has been prudent and efficient in its management of committed augmentation expenditure, and has followed its planning and governance processes.[165]

AER's considerations

The weaknesses PB has identified in VENCorp's project documentation have limited the transparency of VENCorp's application of its decision making processes for

[164] PB Strategic Consulting, *op cit*, p. 21
[165] ibid., p. 51

augmentation expenditure. In particular, the lack of detailed information on how VENCorp measures its own compliance with its augmentation planning and governance processes limits the AER's ability to apply any findings in relation to VENCorp's past expenditure to its assessment of VENCorp's forecast planned augmentation expenditure for the forthcoming regulatory period.

Similarly, while it is clear that VENCorp's overarching principles are based on the requirements of the NER, and guided by the application of the regulatory test to VENCorp's planning approach, the absence of specific references to VENCorp's strategies, overarching policies or plans in the project documentation supplied makes it difficult to determine what role these strategies, policies and plans play, in a practical sense, in VENCorp's decision making process.

These limitations in project documentation mean that the AER has been largely unable to apply the information VENCorp has provided in relation to its committed augmentation expenditure, or PB's findings following its review of that information, to its assessment of VENCorp's forecasts of planned augmentation expenditure and charges.

4.7.3 Forecast planned augmentation charges

4.7.3.1 VENCorp's proposal

To calculate its MAAR building block requirement for forecast planned network augmentation over the forthcoming regulatory period, VENCorp has derived a forecast of planned augmentation charges from its forecast planned augmentation expenditure. VENCorp's forecast of charges has been calculated using:

- straight line current cost depreciation charge over 30 years, which is the average of VENCorp's current projects, and likely to be the average duration over the forecast period[166]
- a nominal vanilla WACC of 8.5%, and
- an allowance of 1.5% of capital costs for the operating and maintenance expenditure likely to be incurred on the capital component of forecast planned augmentations.[167]

4.7.3.2 AER's considerations

The AER has assessed the methodology used by VENCorp in deriving its forecast planned augmentation charges from its forecast planned augmentation expenditure.

To calculate its forecast charges, VENCorp has depreciated its forecast planned augmentation expenditure using a straight line methodology over an assumed average contract life of 30 years. From the AER's understanding of the contracts that VENCorp typically enters into with transmission asset owners, this appears to be a reasonable assumption to use in the calculation of a forecast of planned augmentation charges.

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[166] VENCorp, *op cit*, p. 33.
[167] VENCorp, letter to the AER, 19 July 2007, p. 5. This allowance for opex was not included in VENCorp's initial proposal.

In calculating its forecast planned augmentation charges, VENCorp has applied a nominal vanilla WACC of 8.5% to its forecast of planned augmentation expenditure, which it states is in line with the WACC of 8.76% applied by the AER in its draft decision on Powerlink. The AER notes that the WACC proposed by VENCorp is used to derive a forecast of its planned augmentation charges from its forecast planned augmentation expenditure. Given that the bulk of these augmentations can reasonably be expected to be undertaken by SP AusNet, a WACC determined by reference to Powerlink is unlikely to produce a forecast of planned augmentation charges that reasonably reflects a realistic expectation of the charges that will be paid by VENCorp. Accordingly, the AER does not accept VENCorp's proposed nominal vanilla WACC of 8.5%.

In substitution for the WACC proposed by VENCorp, the AER considers that it is appropriate to use a consistent WACC for both VENCorp and SP AusNet and has therefore applied the 8.85% *indicative* WACC applied in the AER's draft decision on SP AusNet's transmission determination for the same period. The AER notes that the application of the 8.85% WACC in the SP AusNet draft decision is indicative only, and will be updated for the SP AusNet final decision to incorporate more contemporaneous market data. Accordingly, for the VENCorp final decision the AER will apply the WACC approved for SP AusNet in its final decision on SP AusNet's transmission determination, which is to be released in January 2008.

The AER considers that the proposed inclusion of an opex component of 1.5% of its forecast planned augmentation expenditure results in a realistic expectation of the opex component of charges that VENCorp is likely to incur over the forthcoming regulatory period. This assessment is based on the AER's examination of a sample of contracts for non-contestable contracts between SP AusNet and VENCorp from the current regulatory period.

The AER considers that the methodology used by VENCorp in deriving its forecast of planned augmentation charges is appropriate, subject to the inclusion of the revised WACC figure of 8.85%.

When applied to the revised forecast of planned augmentation expenditure determined by the AER on the basis of the analysis in the preceding sections of this chapter, the resultant forecast of planned augmentation charges is that shown in table 4.19 below.

Table 4.19 AER's draft decision — Total forecast planned augmentation charges ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Total
VENCorp's revised proposal	0.36	1.45	6.89	14.00	17.98	22.53	63.21
AER's adjustment	0.01	-0.44	-1.73	-3.33	-2.73	-8.81	-17.03
AER's draft decision	**0.37**	**1.01**	**5.16**	**10.67**	**15.25**	**13.72**	**46.18**

Source: VENDOCS # 215183, AER analysis.

4.8 AER's conclusion

4.8.1 Forecast planned augmentation expenditure

On the balance of the available information, the AER is not satisfied that the forecast of $288m of planned augmentation expenditure in VENCorp's revised proposal reasonably reflects:

- the efficient costs of achieving the capex objectives
- the costs that a prudent operator in VENCorp's circumstances would require to achieve the capex objectives
- a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives.

In particular:

- VENCorp does not appear to have considered the inter-dependencies between its forecast planned augmentation projects and allowances
- In forecasting planned augmentation expenditure VENCorp does not appear to have fully considered the impact of SP AusNet's replacement program on augmentation timing and requirements
- the project documentation provided by VENCorp to support its forecast planned augmentation expenditure was limited, especially with respect to technical data and cost analysis and
- the assumptions in VENCorp's indicative probabilistic forecasting approach, which is typically only used to develop an outlook for years six to ten of a ten year planning period, mean that there is likely to by systemic advancement in the timing of expenditure forecast in its revenue proposal.

In undertaking its assessment of VENCorp's proposed forecast planned network augmentation expenditure in accordance with the NER, the AER has had regard, where relevant, to the capex factors listed at cl. 6A.6.7(e). In forming conclusions with respect to specific elements of VENCorp's proposal, the AER has considered:

- the information presented by VENCorp in and accompanying its revenue proposal and reconciliation with the 2007 EAPR (cl. 6A.6.7(e)(1))
- submissions from interested parties received in the course of consulting on VENCorp's revenue proposal (cl. 6A.6.7(e)(2))
- the AER's own analysis, as outlined in this draft decision, and the analysis and recommendations of PB and Nuttall Consulting (cl. 6A.6.7(e)(3))
- benchmark capex that would be incurred by an efficient TNSP in the circumstances of VENCorp over the regulatory control period (cl. 6A.6.7(e)(4))[168]
- VENCorp's actual and expected augmentation during the current regulatory period (cl. 6A.6.7(e)(5)).

Given that VENCorp's opex is forecast on corporate related costs, the relative prices of operating and capital inputs (cl. 6A.6.7(e)(6)) and the substitution possibilities

[168] PB Strategic Consulting, *op cit*, p. 88-89

between opex and capex (cl. 6A.6.7(e)(7)) have little, if any, bearing upon this draft decision.

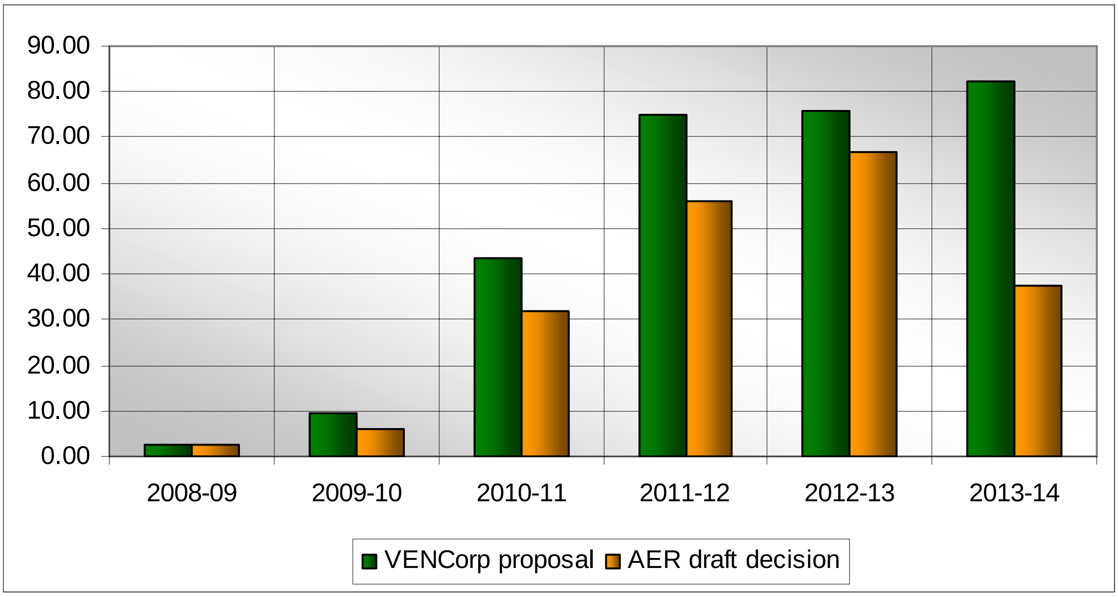
The AER’s adjustments to VENCorp’s forecast planned augmentation expenditure amount to a total reduction of $87.38m, or 30% of VENCorp’s revised proposal. These are shown in table 4.20 below.

Table 4.20 AER’s draft decision — Forecast planned augmentation expenditure ($m, 2007–08)

	2008–09	**2009–10**	**2010–11**	**2011-12**	**2012-13**	**2013-14**	**Total**
VENCorp’s revised proposal	**2.6**	**9.3**	**43.34**	**74.84**	**75.84**	**82.24**	**288.16**
AER’s adjustments							
SP AusNet revised cost estimates	–	–	-1.07	-1.07	-1.07	-1.07	-4.28
VENCorp cost extrapolations	–	-0.3	-0.58	-5.34	-0.58	-1.18	-7.93
Project recommendations	–	-1.1	-4.87	-4.87	-2.37	-37.53	-50.75
Extrapolation of project review findings	–	-1.85	-5.04	-7.45	-5.04	-5.04	-24.42
Total AER adjustment	–	-3.25	-11.54	-18.74	-9.04	-44.82	-87.38
AER’s conclusion	**2.60**	**6.05**	**31.80**	**56.11**	**66.80**	**37.43**	**200.78**

Source: AER analysis.

Figure 4.1 AER's draft decision — Forecast planned augmentation expenditure ($m, 2007–08)



Source: AER analysis.

Once the evident overstatement of the required expenditure in VENCorp's revised proposal is removed, the AER is satisfied that the total recommended forecast of $200.78 reasonably reflects the criteria established in the NER for the purposes of the assessment of capex.

4.8.2 Forecast planned augmentation charges

On the basis of the conclusion above, the AER cannot be satisfied that the forecast of planned augmentation charges that VENCorp has derived from its $288m forecast of planned augmentation expenditure reasonably reflects a realistic expectation of the charges that VENCorp will actually incur. If included in the calculation of VENCorp's MAAR, such a forecast is likely to result in a MAAR that exceeds VENCorp's statutory electricity transmission related costs and therefore fails to satisfy the principles set out in cl. 9.8.4C(a) of the derogation.

Under cl. 6A.6.7(d) of the NER the AER must not, in these circumstances, accept VENCorp's total forecast planned network augmentation charges.

The AER is therefore required under cl. 6A.14.1(2)(ii) to provide an estimate of the total forecast planned augmentation charges that VENCorp will require over the forthcoming regulatory period which the AER is satisfied reasonably reflects the capital expenditure criteria, taking into account the capex factors.

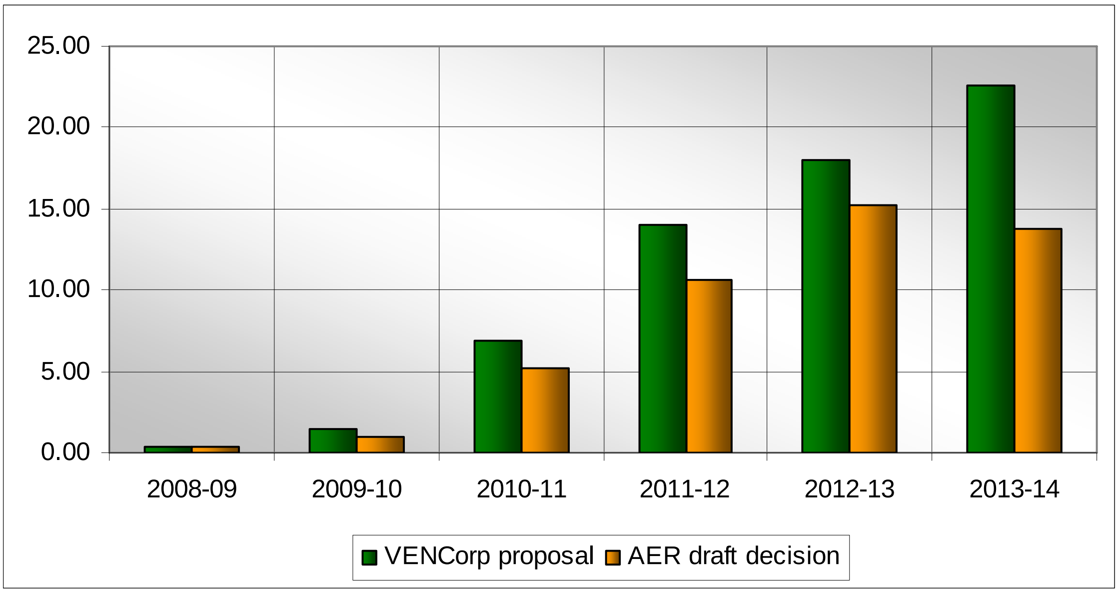
On this basis, the AER's draft decision is that the revised forecast planned augmentation charges in table 4.23 below will be included in VENCorp's MAAR for the forthcoming regulatory period.

Table 4.23 AER's draft decision — Total forecast planned augmentation charges ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Total
VENCorp's proposal	0.36	1.45	6.89	14.00	17.98	22.53	63.21
AER's adjustment	0.01	-0.44	-1.73	-3.33	-2.73	-8.81	-17.03
AER's draft decision	**0.37**	**1.01**	**5.16**	**10.67**	**15.25**	**13.72**	**46.18**

Source: AER analysis.

Figure 4.2 AER's draft decision — Total forecast planned augmentation charges ($m, nominal)



Source: AER analysis.

The AER notes that while much of its analysis has been on a project-by-project basis, that the total forecast planned network augmentation charges should not be taken to bind VENCorp to a particular set of project-specific augmentation budgets, and that VENCorp has the ultimate discretion in making its investment decisions in the forthcoming regulatory period, subject to its not exceeding the MAAR.

5 Maximum allowed aggregate revenue

5.1 Introduction

This chapter sets out the AER's determination of VENCorp's maximum allowed aggregate revenue (MAAR) for each financial year of VENCorp's forthcoming regulatory period.

5.2 Regulatory requirements

Clause 9.8.4B of the derogation states that despite anything to the contrary in chapter 6A or chapter 9, the applicable regime for the regulation of transmission service revenues in respect to the Victorian transmission network (or any part thereof) is, in relation to transmission services provided by VENCorp, the transmission revenue regulatory regime set out in chapter 6A of the NER, as modified by cll. 9.8.4B to 9.8.4E.

Pursuant to cl. 9.8.4C, in determining VENCorp's MAAR for each financial year of the forthcoming regulatory period the AER:

- must apply the following principles:
  - the amount of VENCorp's MAAR must not exceed VENCorp's statutory electricity transmission-related costs, and
  - VENCorp's MAAR must be determined on a full cost recovery but no operating surplus basis.
- must take into account VENCorp's functions under the *Electricity Industry Act 2000* (Vic) relating to the transmission of electricity, the application of the NER to VENCorp and the conditions imposed on VENCorp under its transmission licence, and
- must take into account the difference between the most recent forecast of revenue that VENCorp will be recovered by way of shared transmission network use charges and its statutory electricity transmission-related costs over the current regulatory period (i.e. VENCorp's accumulated surplus/deficit at the end of the current regulatory period).

Clause 9.3.1 states that VENCorp's statutory electricity transmission-related costs are the sum of:

- its aggregate actual costs in operating and planning the Victorian Transmission Network
- all network charges payable by VENCorp to SP AusNet or any other owner of the Victorian Transmission Network or a part of the Victorian Transmission Network, including charges relating to augmentations
- all other charges payable by VENCorp to providers of network support services and other services which VENCorp uses to provide network services that are transmission services, and

- any other costs that directly arise out of VENCorp's functions under the *Electricity Industry Act 2000* (Vic) relating to the transmission of electricity, the application of the NER to VENCorp or the conditions imposed on VENCorp under its transmission licence relating to the transmission of electricity, for which there is no alternative method (legislative or contractual) for the recovery of those costs.

5.3 VENCorp's proposal

On 17 July 2007, VENCorp revised the forecasts for several components of its MAAR. In its revised proposal, VENCorp proposes a total MAAR of $2 889.8m (nominal) for its forthcoming regulatory period.[169] The revisions from VENCorp's initial proposal consist of:

- revisions to VENCorp's planned augmentation charges to reconcile the charges with the planned augmentation outlined in its 2007 electricity annual planning report (EAPR), which was published on 21 June 2007 after the submission of its initial proposal, and
- revisions to VENCorp's prescribed services charges to reflect a change in the recognition of the availability incentive scheme (AIS). VENCorp states that, having had the opportunity to consider SP AusNet's revenue proposal, VENCorp has now removed the allowance sought for rebates under the AIS in its initial proposal, given that SP AusNet has sought a rebate allowance in its revenue proposal.[170]

For the purposes of assessing VENCorp's proposal under the NER, the AER accepts VENCorp's proposal as incorporating the revisions listed above and submitted to the AER on 17 July 2007. VENCorp's proposal (as revised) is outlined in the table below.

[169] VENCorp, Letter to AER – Reconciliation of VENCorp Electricity Transmission Network Revenue Proposal for the Period 1 July 2008 to 30 June 2014 with the 2007 Electricity Annual Planning Report, 19 July 2007, p. 6
[170] ibid.

Table 5.1 VENCorp proposal – MAAR (nominal $m)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
Operating expenditure	6.69	6.98	7.17	7.47	7.71	7.98	44.00
Committed augmentation charges	22.90	23.60	24.30	25.00	25.70	26.50	148.00
Planned augmentation charges	0.36	1.45	6.89	14.00	17.98	22.53	63.21
Total VENCorp expenditure	**30.00**	**32.00**	**38.40**	**46.50**	**51.40**	**57.00**	**255.20**
Prescribed services charges	370.00	393.50	418.60	445.20	473.50	503.70	2 604.50
MAAR*	**405.00**	**430.50**	**462.00**	**496.70**	**529.90**	**565.70**	**2 889.80**
Energy (Mwh)	52.35	51.67	51.67	51.81	52.78	53.38	
TUOS charges ($/Mwh)	7.74	8.33	8.94	9.59	10.04	10.60	

Source: VENCorp[171]

VENCorp's revised proposal has removed the annual $6m allowance for the AIS from its forecast prescribed service charges, but its MAAR erroneously includes the allowance. The MAAR calculation in this table also includes an annual reduction of $1m to account for interest income that VENCorp will earn during the regulatory period.

Details of VENCorp's proposed forecasts of operating expenditure, committed augmentation charges and planned augmentation charges are discussed in chapters 2, 3 and 4 respectively.

VENCorp states that the prescribed services charges consist of forecast payments by VENCorp to SP AusNet and Murraylink for the provision of prescribed services provided by these TNSPs. VENCorp states the prescribed services charges relating to SP AusNet have been provided by SP AusNet, and VENCorp has not made any amendments to these forecasts. These forecasts are based on SP AusNet's initial revenue proposal (submitted 28 February 2007), and assume that VENCorp will be charged 85% of SP AusNet's non-easement tax maximum allowed revenue, and 100% of SP AusNet's easement tax liability.[172] As mentioned above, on 17 July 2007, VENCorp revised its proposal to remove the AIS rebate allowance from its forecast of prescribed services charges, as SP AusNet had already sought an allowance for these rebates in its revenue proposal.

[171] ibid., p. 6
[172] VENCorp, *VENCorp Electricity Revenue Cap Proposal – 1 July 2008 to 30 June 2014,* 1 May 2007, pp. 39-40

VENCorp states the prescribed services charges relating to Murraylink are based on Murraylink's revenue cap decision (1 October 2003), and the agreement between VENCorp and ElectraNet on the allocation of prescribed charges between Victoria and South Australia.[173]

Attachment 8of VENCorp's initial proposal contains a "reconciliation statement" stating VENCorp expected its 2007-08 surplus to be zero, and its accumulated surplus at the end of 2007-08 to be $24.61m (nominal). On 9 August 2007, VENCorp informed the AER that this statement was incorrect, and that it in fact expected a deficit of $24.61m (nominal) in 2007-08, and an accumulated surplus of zero at the end of 2007-08.

5.4 Issues and AER's considerations

5.4.1 Operating expenditure

VENCorp's proposal includes a total opex forecast of $44.00m (nominal). The AER has not accepted this opex forecast and has substituted an opex forecast that is reduced by $4.63m (nominal). The reasons for the AER's draft decision on VENCorp's opex are set out in chapter 2.

Table 5.2 AER's draft decision – operating expenditure (nominal $m)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
VENCorp's proposal	6.69	6.98	7.17	7.47	7.71	7.98	**44.00**
AER's adjustment	-0.70	-0.78	-0.74	-0.80	-0.80	-0.81	**-4.63**
AER's draft decision	**5.99**	**6.20**	**6.43**	**6.67**	**6.91**	**7.17**	**39.37**

Source: VENCorp[174], AER analysis

5.4.2 Committed augmentation charges

VENCorp's proposal includes a total forecast of committed augmentation charges for the forthcoming regulatory period of $148.0m (nominal). The AER has not accepted this estimate and has substituted an estimate that is reduced by $22.84m (nominal), to correct acknowledged errors in VENCorp's calculation of its forecast. The reasons for the AER's draft decision on VENCorp's committed augmentation charges are set out in chapter 3.

Table 5.3 AER's draft decision – committed augmentation charges (nominal $m)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
VENCorp's proposal	22.9	23.6	24.3	25.0	25.7	26.5	148.0
AER's adjustment	-3.55	-3.67	-3.77	-3.86	-3.92	-4.07	-22.84
AER's draft decision	**19.35**	**19.93**	**20.53**	**21.14**	**21.78**	**22.43**	**125.16**

[173] VENCorp, *op cit*, p. 39
[174] VENCorp, *op cit*, p. 35

Source: VENCorp, AER analysis

5.4.3 Planned augmentation charges

VENCorp's revised proposal includes a total forecast of planned augmentation charges of $63.21m (nominal). The AER has not accepted this estimate and has substituted an estimate that is reduced by $17.03m (nominal). The reasons for the AER's draft decision on VENCorp's planned augmentation charges are set out in chapter 4.

Table 5.4 AER's draft decision – planned augmentation charges (nominal $m)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
VENCorp's proposal	0.36	1.45	6.89	14.00	17.98	22.53	63.21
AER's adjustment	+0.01	-0.44	-1.73	-3.33	-2.73	-8.81	-17.03
AER's draft decision	**0.37**	**1.01**	**5.16**	**10.67**	**15.25**	**13.72**	**46.18**

Source: VENCorp, AER analysis

5.4.4 Prescribed services charges

VENCorp's revised proposal includes a total prescribed services charges forecast of $2 604.50m (nominal). These charges relate to payments made by VENCorp to SP AusNet and Murraylink for the provision of prescribed transmission services. The AER notes that certain assumptions must be made to derive a forecast of prescribed services charges – the AER's assessment of the assumptions made by VENCorp follows.

5.4.4.1 SP AusNet prescribed services charges

- Prescribed services charges payable to SP AusNet comprise the majority of VENCorp's prescribed services charges forecast. VENCorp's forecast was based on SP AusNet's original revenue proposal. The AER, in its draft decision on SP AusNet's revenue determination, did not accept SP AusNet's proposal in its entirety. The AER has updated this aspect of VENCorp's proposal to reflect the outcome of the SP AusNet draft decision. The AER notes that these charges will need to be updated again after the release of the AER's final decision on SP AusNet, should the final decision differ from the draft decision.
- The AER has corrected for the difference in regulatory years between SP AusNet and VENCorp, which the AER understands VENCorp did not do in its proposal.[175] In making this correction the AER was required to make an assumption about SP AusNet's MAR for the first year beyond its forthcoming regulatory control period. The AER adopted the x factor and forecast inflation rate in the SP AusNet draft decision to make this extrapolation. The AER also assumed that SP AusNet's charges are applied uniformly over each year.
- The AER accepts VENCorp's assumptions that 85% of SP AusNet's (non-easement tax) MAR and 100% of SP AusNet's easement tax is recovered through VENCorp. Information provided by VENCorp indicates that approximately 85%

[175] Email VENCorp to AER, 21 September 2007

of SP AusNet's MAR has been recovered from VENCorp through use of system charges over the current regulatory period.

5.4.4.2 Murraylink prescribed services charges

- VENCorp's prescribed services charges forecast appears to have been based on the ACCC's 2003 Murraylink decision.[176] This decision was revoked and substituted in 2004.[177] The AER has forecast the Murraylink prescribed services charges from the substituted decision.
- As VENCorp's forthcoming regulatory period extends one year beyond Murraylink's current regulatory period the AER was required to make an assumption about Murraylink's MAR for the first year beyond its current regulatory period. The AER adopted the x factor and forecast inflation rate in the Murraylink decision to make this extrapolation.
- The AER accepts VENCorp's assumption that 55% of Murraylink's MAR is recovered through VENCorp. The AER understands this allocation is based on an agreement between VENCorp and ElectraNet.

Based on the above assumptions the AER has made a downward adjustment of $70.09m (nominal) to VENCorp's total forecast prescribed service charges. As previously noted, this adjustment will need to be updated to reflect differences (if any) between the SP AusNet draft and final decisions.

Table 5.5 AER's draft decision – prescribed services charges (nominal $m)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
VENCorp's proposal	370.00	393.50	418.60	445.20	473.50	503.70	2 604.50
AER's adjustment	+3.57	-1.34	-7.74	-13.85	-21.56	29.17	-70.09
AER's draft decision	**373.57**	**392.16**	**410.86**	**431.35**	**451.94**	**474.53**	**2 534.41**

Source: VENCorp, AER analysis

5.4.5 Other adjustments

5.4.5.1 Interest income

In its proposal, VENCorp reduced the sum of its forecast opex, committed augmentation charges, planned augmentation charges and prescribed services charges by $1.00m (nominal) in each year, to account for the interest income VENCorp expects to earn annually during its forthcoming regulatory period.[178]

[176] ACCC, *Decision – Murraylink Transmission Company Application for Conversion and Maximum Allowed Revenue*, 1 October 2003.
[177] ACCC, *Revocation and substitution of revenue cap*, letter to Murraylink Transmission Company, 1 April 2004.
[178] VENCorp, *op cit*, p. 40

The AER considers the reduction of forecast interest income from VENCorp's forecast statutory electricity transmission-related costs is important to ensure that VENCorp's MAAR is determined on a full cost recovery but no operating surplus basis.

In the most recent full financial year (2006-07), VENCorp's electricity segment budgeted to earn $1.02m (nominal) interest income, but instead received $2.15m (nominal). The likely cause of this appears to be VENCorp receiving significantly more settlement residue than expected ($65.63m actual compared to $35.00m budgeted, nominal). The AER notes that there are some factors that will affect VENCorp's future revenues, such as settlement residue, that cannot be fully controlled, and that VENCorp's interest income is likely to vary year to year. However, the AER considers that if VENCorp is able to operate close to a no operating surplus throughout the forthcoming regulatory period then its interest income should be minimal.

The AER accepts VENCorp's forecast of interest income as reasonable, noting that based on recent experience, it may be on the conservative side and potentially understates the amount of interest income VENCorp will, in the end, earn over the forthcoming regulatory period.

5.4.5.2 Accumulated surplus

Each year when it sets its transmission charges for the following year, VENCorp has informed the AER that, with the aim of operating on a full cost recovery but no operating surplus basis, it takes into account its accumulated surplus from the current year. However, at the time VENCorp is setting its charges the accumulated surplus from the current year cannot be known with certainty, and accordingly VENCorp must estimate this amount.

The AER understands that at the time VENCorp set its 2007-08 transmission charges, it was expecting an accumulated surplus at the end of 2006-07 of $26.61m (nominal). Accordingly VENCorp set its 2007-08 transmission charges with the aim of achieving a deficit of $26.61m (nominal) in 2007-08, and thus an accumulated surplus/deficit at the end of 2007-08 of zero.

However, VENCorp's financial accounts indicate that at the end of 2006-07 it had an accumulated surplus of $49.80m (nominal), instead of the expected $26.61m (nominal). This appears to be the result of VENCorp receiving significantly more settlement residue than expected. As VENCorp's 2007-08 transmission charges are already set, it is still expected to achieve a deficit in 2007-08 of $26.61m (nominal). However, because VENCorp's accumulated surplus at the end of 2006-07 was greater than its forecast at the time charges were set, this is now expected to lead to an accumulated surplus of $25.19m (nominal) at the end of 2007-08, instead of an accumulated surplus of zero.

Pursuant to cl. 9.8.4C(e)(iii) of the NER, the AER must take into account the accumulated surplus in determining VENCorp's MAAR for the forthcoming regulatory period. The AER proposes to deduct the full amount of VENCorp's expected 2007-08 accumulated surplus from its MAAR in 2008-09, which is consistent with the approach that VENCorp itself follows in setting its transmission charges.

5.4.5.3 AIS rebate allowance

As noted above, when VENCorp submitted its revised proposal it stated its intention to revise its proposal to remove the AIS rebate allowance from its forecast of prescribed services charges, as SP AusNet had already sought an allowance for these rebates in its revenue proposal. While VENCorp removed the allowance from its prescribed services charges forecast, it did not remove the allowance from the overall MAAR presented in the revised proposal. The AER has corrected the error in VENCorp's calculations.

5.5 AER's conclusion

The table below sets out the AER's determination of VENCorp's MAAR for each financial year of the forthcoming regulatory period, as required by cl 9.8.4C(e)(4).

Table 5.6 AER's draft decision – MAAR (nominal $m)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
Operating expenditure	5.99	6.20	6.43	6.67	6.91	7.17	**39.37**
Committed augmentation charges	19.35	19.93	20.53	21.14	21.78	22.43	**125.16**
Planned augmentation charges	0.37	1.01	5.16	10.67	15.25	13.72	**46.18**
Total VENCorp expenditure	**25.70**	**27.14**	**32.12**	**38.48**	**43.94**	**43.31**	**210.71**
Prescribed services charges	373.57	392.16	410.86	431.35	451.94	474.53	**2 534.41**
minus Interest income	-1.00	-1.00	-1.00	-1.00	-1.00	-1.00	-6.00
minus Accumulated surplus	-25.19						-25.19
MAAR	**373.08**	**418.30**	**441.98**	**468.84**	**494.88**	**516.85**	**2713.93**

Source: AER analysis

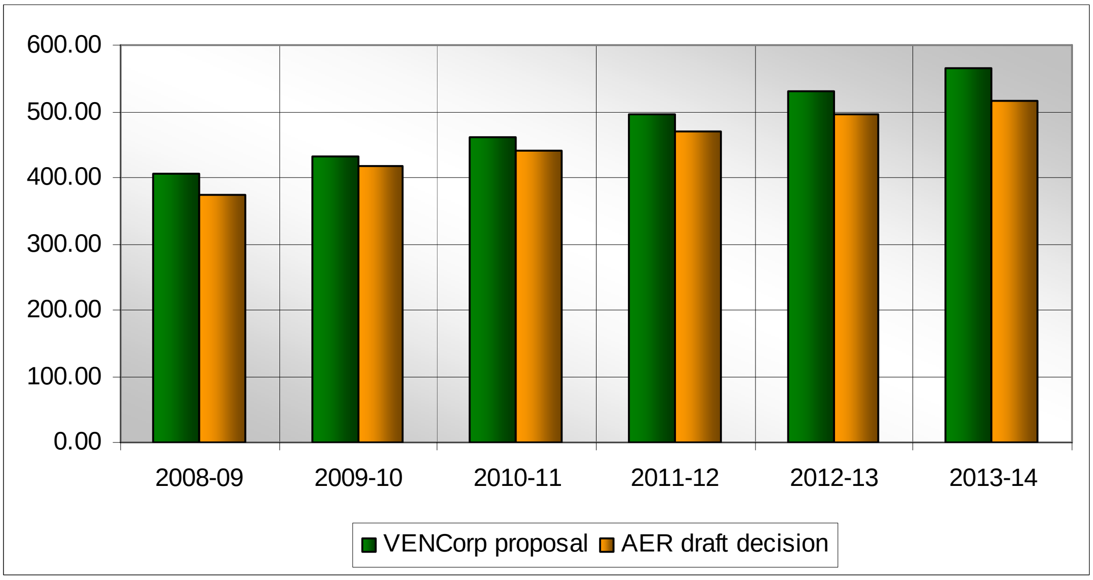
In its revised proposal, VENCorp proposed a total MAAR of $2 889.80m (nominal), over the forthcoming regulatory period. The AER has made a total reduction of $175.87m (nominal) to this amount, resulting in a total MAAR of $2 713.93m (nominal).

Table 5.7 AER's draft decision – MAAR (nominal $m)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
VENCorp's proposal	405.00	430.50	462.00	496.70	529.90	565.70	2 889.80
AER's adjustment	-31.92	-12.20	-20.02	-27.86	-35.02	-48.85	-175.87
AER's draft decision	**373.08**	**418.30**	**441.98**	**468.84**	**494.88**	**516.85**	**2713.93**

Source: VENCorp, AER analysis

Figure 5.1 AER's draft decision – MAAR (nominal $m)



Source: VENCorp, AER analysis

Indicative price path

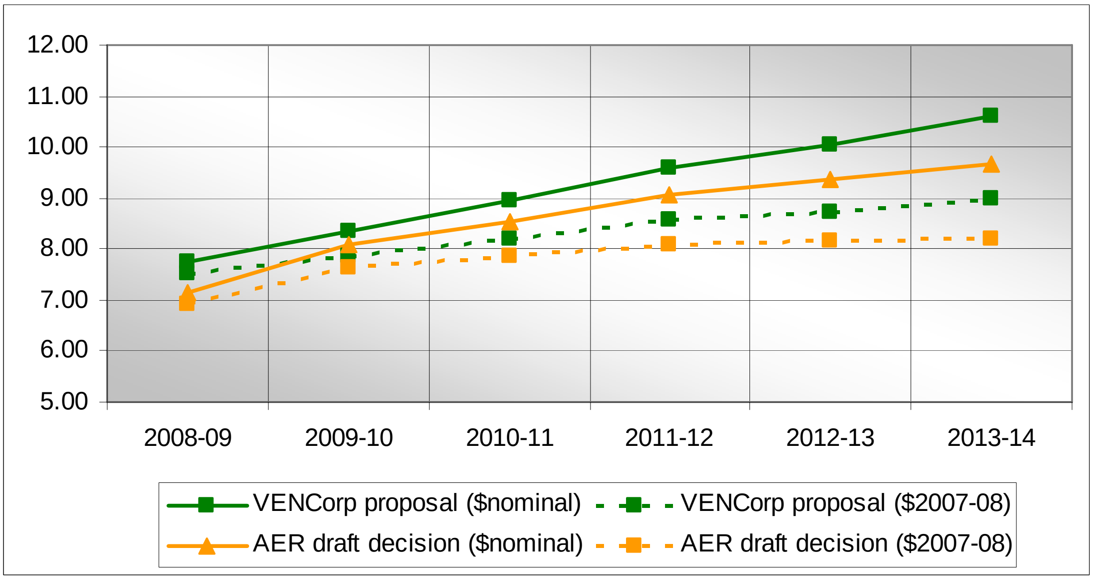
The following indicative TUOS price path is based on the AER's draft decision on VENCorp's MAAR, and the demand forecasts contained in VENCorp's proposal.

Table 5.8 AER's draft decision – Indicative TUOS price path ($/Mwh)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Average
VENCorp's proposal ($nominal)	7.74	8.33	8.94	9.59	10.04	10.60	**9.21**
VENCorp's proposal ($2007-08)	7.51	7.86	8.20	8.56	8.73	8.98	**8.31**
AER's draft decision ($nominal)	7.13	8.10	8.55	9.05	9.38	9.68	**8.65**
AER's draft decision ($2007-08)	6.92	7.64	7.85	8.08	8.15	8.20	**7.81**

Source: VENCorp, AER analysis

Figure 5.2 AER's draft decision – Indicative TUOS price path ($/Mwh)



Source: VENCorp, AER analysis

6 Determination of negotiating framework

6.1 Introduction

This chapter discusses the AER's assessment of VENCorp's proposed negotiating framework.

The negotiating framework stipulates the minimum procedural requirements that a TNSP must undertake in negotiating the terms and conditions of access with an applicant seeking a negotiated transmission service. In accordance with chapter 6A, part K, a commercial arbitrator must have regard to the negotiating framework where disputes in relation to negotiated services arise.

There are three types of negotiated transmission services that a service applicant may request and negotiate with a TNSP. These services include:

- connection services (which might include entry, exit and TNSP to MNSP connection services)
- shared transmission services that exceed the network performance requirements that the shared transmission services are required to meet under any legislation of a participating jurisdiction; or exceed or do not meet the network performance requirements set out in the NER
- use of system services relating to augmentations or extensions required to be undertaken.[179]

The negotiating framework only relates to negotiated services. Pricing of prescribed transmission services is covered by the pricing methodology considered in chapter 8 of this draft decision.

6.2 Regulatory requirements

Clause 6A.2.2(2) of the NER states that a transmission determination made by the AER pursuant to cl. 6A.2.1 must include a determination relating to the TNSP's negotiating framework.

[179] Definition "Negotiated Transmission Service", chapter 10, NER

6.2.1 TNSP's proposal

In accordance with cl. 6A.9.5(a) of the NER, a TNSP must prepare a document setting out the negotiation procedure to be followed by the TNSP and any parties applying for a negotiated transmission service, as to the terms and conditions of access. Under clause 6A.10.1(b) of the NER, the TNSP must submit its proposed negotiating framework at the time of submitting its revenue proposal to the AER.

Consistent with cl. 6A.9.5(b) of the NER, the negotiating framework for a TNSP must comply with and be consistent with the applicable requirements of a transmission determination. It must also comply with the requirements of cl. 6A.9.5(c). These requirements are discussed below.

Under cl. 6A.10.1(c) of the NER, the proposed negotiating framework must contain or be accompanied by such information as required by the submission guidelines made for that purpose under cl. 6A.10.

6.2.2 AER determination of negotiating framework

Under cl. 6A.9.5(c) of the NER, a TNSP's negotiating framework must specify:

(1) a requirement for the provider and service applicant to negotiate in good faith the terms and conditions of access for provision of the negotiated transmission service

(2) a requirement for the provider to provide all such commercial information as a service applicant may reasonably require to enable that applicant to engage in effective negotiation with the provider for the provision of the negotiated transmission service, including the cost information described in subparagraph (3)

(3) a requirement for the provider to identify and inform a service applicant of the reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the negotiated transmission service and demonstrate to a service applicant that the charges for providing the negotiated transmission service reflect those costs and/or the cost increment or decrement (as appropriate)

(4) a requirement for a service applicant to provide all such commercial information as the provider may reasonably require to enable the provider to engage in effective negotiation with that applicant for the provision of the negotiated transmission service

(5) a reasonable period of time for commencing, progressing and finalising negotiations with a service applicant for the provision of the negotiated transmission service, and a requirement that each party to the negotiation must use its reasonable endeavours to adhere to those time periods during the negotiation

(6) a process for dispute resolution which provides that all disputes as to the terms and conditions of access for provision of negotiated transmission services are to be dealt with in accordance with Part K of Chapter 6A of the NER

(7) the arrangements for payment by a service applicant of the provider's reasonable direct expenses incurred in processing the application to provide the negotiated transmission service

(8) a requirement that the transmission network service provider determine the potential impact on other transmission network uses of the provision of the negotiated transmission service, and

(9) a requirement that the transmission network service provider must notify and consult with any affected transmission network users and ensure that the provision of the negotiated

transmission service does not result in non-compliance with obligation in relation to other transmission network users under the rules.

Clause 6A.9.3 of the NER requires the AER's determination relating to the negotiating framework to set out requirements for the preparation, replacement, application or operation of the provider's negotiating framework.

The AER must make a decision to either approve or refuse the TNSP's proposed negotiating framework, and set out reasons for its decision.[180]

If the AER refuses to approve the proposed negotiating framework, the AER must include in its decision an amended negotiating framework, determined on the basis of the current proposed negotiating framework. The AER will only amend the negotiating framework to the extent necessary to make it compliant with the NER.[181]

6.3 VENCorp's proposal

VENCorp's proposed negotiating framework for access to negotiated transmission services states that it will negotiate in good faith and will use reasonable endeavours to commence, progress and finalise negotiations in a timely manner.[182]

VENCorp's proposed framework states that, subject to confidentiality obligations, VENCorp and the applicant will provide such commercial information as may be reasonably required to engage in effective negotiations.[183] Subject to exceptions, confidentiality restrictions placed on any information provided by either party must be observed.[184]

Upon application for a negotiated transmission service, VENCorp proposes a minimum fee, payable by the applicant, of $15 000. Additional direct expenses incurred by VENCorp are to be paid by the applicant as reasonably required.[185] VENCorp proposes to inform the applicant of reasonable costs, or changes in costs in the provision of the negotiated transmission service.[186]

VENCorp states in its proposal that it will notify and consult any transmission network user that may be affected as a result of a negotiated transmission service.[187]

VENCorp's proposed negotiating framework provides that VENCorp and the service applicant shall comply with the terms of the framework where it is consistent with the NER.[188]

VENCorp's proposal states that any disputes concerning negotiations for negotiated transmission services are subject to part K of chapter 6A of the NER.[189]

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180 NER cl. 6A.14.1(6).
181 NER cl. 6A.13.2(c).
182 VENCorp, *VENCorp Electricity Revenue Cap Proposal – 1 July 2008 to 30 June 2014,* p. 48
183 ibid.
184 ibid.
185 ibid., p. 49.
186 ibid., p. 48.
187 ibid., p. 49.
188 ibid., p. 49.

6.4 Submissions

The AER received no submissions in response to VENCorp's proposed negotiating framework.

6.5 Issues and the AER's considerations

This section sets out the AER's considerations in assessing whether VENCorp's proposed negotiating framework is compliant with the NER.

The preparation, application and operation of VENCorp's negotiating framework is to be in accordance with the requirements of cl. 6A.9.5 of the NER and the amendments required in this draft decision. The negotiating framework determined in the AER's final decision will have effect from the commencement of the transmission determination on 1 July 2008 until its conclusion on 30 June 2014, at which time VENCorp may seek to amend or replace it for the purposes of its proposed negotiating framework for regulatory period commencing 1 July 2014.

6.5.1 Proposed negotiating framework — compliance with clause 6A.9.5

The AER has assessed the adequacy of VENCorp's proposed negotiating framework against cl. 6A.9.5(c), which sets out the minimum requirements for a negotiating framework. These requirements primarily relate to the conduct of parties during the negotiation process.

6.5.1.1 Negotiate in good faith

Clause 6A.9.5(c)(1) requires VENCorp's negotiating framework to state that VENCorp and a service applicant will negotiate in good faith the terms and conditions of access for the provision of negotiated transmission services.

Part 1 of VENCorp's proposed framework provides that VENCorp and a service applicant will negotiate in good faith the terms and conditions of access for the provision of negotiated transmission services.[190]

The proposed framework complies with this requirement, and reflects cl. 6A.9.5(c)(1).

6.5.1.2 Provision of commercial information by VENCorp

In accordance with cl. 6A.9.5, part 2 of the proposed negotiating framework states that VENCorp will provide all such commercial information as a service applicant may reasonably require to enable the service applicant to engage in effective negotiation with VENCorp for the provision of negotiable services. [191] VENCorp also undertakes to provide a description of the nature of the services to be provided. The provision of information is subject to confidentiality obligations to any third party.

VENCorp's proposed negotiating framework complies with cl. 6A.9.5(c)(2).

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189 ibid., p. 49
190 ibid., p. 48
191 ibid., p. 48

6.5.1.3 Provision of cost information

Clause 6A.9.5(c)(3) of the NER requires VENCorp, in its negotiating framework, to undertake to identify and inform the service applicant of the reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the negotiated transmission service. It also requires VENCorp to demonstrate to the service applicant that the charges for providing such a service reflect those costs and/or the cost increment or decrement.

VENCorp states in its proposed negotiating framework that it shall inform a service applicant of the reasonable costs, or change in costs, of VENCorp providing negotiated transmission services to the service applicant, and shall demonstrate to the service applicant that these reflect the costs, or change in costs, of VENCorp providing the negotiated transmission services.[192]

This is consistent with the requirements of cl. 6A.9.5(c)(3).

6.5.1.4 Provision of commercial information by connection applicant

In accordance with cl. 6A.9.5(c)(4), part 2 of the proposed negotiating framework requires a service applicant to provide all such commercial information as VENCorp may reasonably require to enable VENCorp to engage in effective negotiation with the service applicant for the provision of negotiated transmission services. Further, VENCorp requires the service applicant to provide a detailed description of the negotiable service required. VENCorp states that the provision of information is subject to confidentiality obligations to any third party.[193]

Part 2 of VENCorp's proposed negotiating framework is compliant with cl. 6A.9.5(c)(4).

6.5.1.5 Reasonable timeframe for negotiation

To comply with cl. 6A.9.5(c)(5), VENCorp must specify a reasonable period of time for commencing, progressing and finalising negotiations with a service applicant for the provision of the negotiated transmission service, and a requirement that each party to the negotiation must use its reasonable endeavours to adhere to those time periods during the negotiations.

In part 1 of its proposed negotiating framework, VENCorp claims that it will comply with the timeframes for connection required under rule 5.3. Further, VENCorp establishes that it and the service applicant shall use reasonable endeavours to commence, progress and finalise negotiations in a timely manner.[194]

VENCorp's proposed negotiating framework satisfies the requirements of cl. 6A.9.5(c)(5).

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192 ibid., p. 48
193 ibid.
194 ibid.

6.5.1.6 Dispute resolution process

Clause 6A.9.5(c)(6) requires the negotiating framework to set out a process for dispute resolution in which all disputes as to the terms and conditions of access for the provision of negotiated transmission services are to be dealt with in accordance with part K of chapter 6A.

VENCorp's proposed negotiating framework, in part 5, provides that all disputes concerning negotiated transmission services shall be dealt with in accordance with part K of chapter 6A of the NER.

The proposed negotiating framework is consistent with the requirements of cl. 6A.9.5(c)(6).

6.5.1.7 Payment of reasonable direct expenses incurred by service applicant

As required by cl. 6A.9.5(c)(7), VENCorp must set out in its negotiating framework arrangements for payment of VENCorp's reasonable direct expenses incurred in processing the application to provide the negotiated transmission service. Clause 6A.9.1(1) requires that prices for a negotiated transmission service be based on the costs incurred in providing that service.

The proposed negotiating framework provides that a service applicant shall pay VENCorp's reasonable direct expenses incurred in processing the application for negotiated transmission services. VENCorp will generally require a service applicant to pay an initial fee upon application, by way of a first instalment. This fee is intended to cover VENCorp's minimum anticipated reasonable direct expenses for processing the application. The minimum application fee is currently $15 000.[195] There is no express provision in VENCorp's proposed negotiating framework for a refund where costs incurred do not reach $15 000.

To ensure consistency with cl. 6A.9.1(1) the AER requires insertion of the words: "In the event that VENCorp's reasonable direct expenses are less than the application fee paid by the Service Applicant, VENCorp will refund or credit the difference to the Service Applicant". This amendment is indicated in bold type in appendix B.

This amendment will render VENCorp's proposal for the payment of expenses incurred in processing an application consistent with cl. 6A.9.5(c)(7) of the NER.

6.5.1.8 Impact on other transmission network users

As required by cl. 6A.9.5(c)(8), VENCorp states in its proposed negotiating framework that it will determine the potential impact the provision of a negotiated transmission service will have on other transmission network users.

The proposed negotiating framework complies with cl. 6A.9.5(c)(8).

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195 ibid. p. 49

6.5.1.9 Notification and consultation with any affected user

Clause 6A.9.5(c)(9) requires the TNSP to specify in its negotiating framework that it will notify and consult with any affected transmission network user. It also ensures that the provision of the negotiated transmission service does not result in non-compliance with obligations in relation to other transmission network users under the NER.

VENCorp states in its proposed negotiating framework that it will notify and consult with any affected transmission network users to ensure that the provision of a negotiated transmission service does not result in non-compliance with obligations in relation to those transmission network users under the NER or under contractual agreements with VENCorp.

This is consistent with cl. 6A.9.5(c)(9) the principles set out at cl. 6A.9.1 of the NER.

6.6 AER's determination

The AER considers that only one aspect of VENCorp's proposed negotiating framework for the forthcoming regulatory period does not satisfy the minimum requirements of cl. 6A.9.5(c).

Appendix B sets out VENCorp's negotiating framework and identifies (in **bold**) the changes required in order for it to be compliant with the NER, and receive the AER's approval.

7 Determination of negotiated transmission service criteria

7.1 Introduction

The NER require the AER to include in its transmission determination the negotiated transmission service criteria (negotiating criteria) that will apply to VENCorp in the forthcoming regulatory control period. The negotiating criteria are to be applied by VENCorp in negotiating the terms and conditions, including price, and any access charges for, a negotiated transmission service. In the event of a dispute in relation to the terms and conditions of access, or any charges to be paid to VENCorp, a commercial arbitrator must apply the negotiating criteria.

Unlike other elements of this transmission determination, VENCorp is not required to submit proposed negotiating criteria to the AER. The AER must determine and specify the criteria in accordance with the NER, as it has done in this draft decision.

7.2 Regulatory requirements

Under cl. 6A.2.2 (3) of the NER, a transmission determination made pursuant to cl. 6A.2.1 must include a determination of the negotiating criteria that will apply to the TNSP.

Clause 6A.9.4 (a) states that the AER's determination must set out the negotiated transmission service criteria that will be applied:

- by the TNSP in negotiating the terms and conditions of access for negotiated transmission services, including prices to be charged for the provision of the service and any access charges which are negotiated by the TNSP during the relevant regulatory control period, and
- by a commercial arbitrator in resolving any dispute between a TNSP and a person wishing to receive a negotiated transmission service in relation to the terms and conditions of access to the service, including the price to be charged for the provision of the service, and any access charges that are to be paid to the TNSP.

Clause 6A.9.4 (b) of the NER requires the negotiating criteria determined by the AER to give effect to and be consistent with the negotiated transmission service principles (the principles) set out in cl. 6A.9.1.

7.3 Submissions

The AER received two submissions on the proposed negotiating criteria for VENCorp. These were from VENCorp and the Southern Generators.[196]

[196] Southern Generators includes AGL, Flinders Power, International Power Australia, Loy Yang Power Marketing and Management Company and TRUenergy.

VENCorp

VENCorp notes that the negotiating criteria proposed by the AER effectively restate the principles set out in cl. 6A.9.1.[197] VENCorp prefers that the principles be adopted by reference, as opposed to restatement. VENCorp submits that this will limit potential debate on consistency between the principles and the negotiating criteria.[198]

Southern Generators

The Southern Generators make three comments on the negotiating criteria.

Firstly, the Southern Generators submit that the negotiating criteria should not be limited to a restatement of the principles. The Southern Generators assert that the negotiating criteria should inform TNSPs and service applicants what terms and conditions (including price) should or should not be included in their agreements.[199]

The Southern Generators state that negotiating criteria 5, 6, 7, 8 and 9 mirror the principles by stating that prices for negotiated transmission services are to be reflective of cost. The Southern Generators assert that a TNSP's prices should be determined by reference only to *efficient* costs of providing a service. The Southern Generators state that such a requirement would be consistent with the Australian Energy Market Commission's (AEMC) rule determination in support of the National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18.[200]

Finally, the Southern Generators submit that the negotiating criteria should reflect the wording of cl. 6A.9.1 as closely as possible, and submit that differences in wording will create uncertainty and may be used by TNSPs as a lever to bring about unfair results for their customers.[201]

7.4 Issues and AER's considerations

This section sets out the AER's considerations in determining negotiating criteria for VENCorp that give effect to, and are consistent with, the requirements of the NER.

7.4.1 Determining the negotiated transmission service criteria

Clause 6A.9.4 (b) requires the negotiating criteria established by the AER to give effect to, and be consistent with the negotiated transmission service principles contained in cl. 6A.9.1.

In accordance with cl. 6A.11.3, the AER published its proposed criteria for VENCorp for the forthcoming regulatory period for consultation prior to the release of this draft decision.

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[197] VENCorp, *Submission on the Proposed Negotiated Transmission Service Criteria for SP AusNet and VENCorp*, 7 August 2007, p. 1
[198] ibid., p. 2
[199] Southern Generators, *Negotiated Transmission Service Criteria Submission*, 8 August 2007, p. 1
[200] ibid., p. 1
[201] ibid., p. 2

7.4.2 Submissions on the proposed negotiated transmission service criteria

Both VENCorp and the Southern Generators submit that the negotiating criteria should repeat the principles, with no alterations to the wording. VENCorp and the Southern Generators assert that this will prevent deliberations on consistency. The AER considers rewording necessary to present the negotiating criteria as enforceable requirements, rather than mere guiding principles.

The Southern Generators submit that the negotiating criteria should provide that TNSP prices accurately reflect costs, and that these costs are efficient costs only. This submission is based upon the AEMC's rule determination on the National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18, [202]which refers to the efficiency of costs charged by the TNSP. Only part of the AEMC's statement was quoted in the Southern Generators' submission. The remainder of the statement is included in *italics* below.

> Moreover, requiring generators and large end-users to negotiate with TNSPs about the recovery of costs directly incurred by the TNSP as a consequence of their connection will ensure that the efficiency of those costs is subject to increased scrutiny *by a well informed and commercially interested counter-party.*

The principles themselves do not refer explicitly to the efficiency of costs. The AEMC's rule determination states that the substantial market power of TNSPs is counteracted by the fact that end-users of negotiated services are likely to be larger and well resourced, providing a counterweight to the market power possessed by the TNSP and making a commercial negotiation a viable proposition.[203] The rule determination contemplates that service applicants will scrutinise the efficiency of costs incurred by the TNSP and subsequently passed on to the service applicant. The AER does not consider that the inclusion of an efficiency requirement in the criteria is necessary to give effect to the principles.

The details sought for inclusion by the Southern Generators are considered by the AER to be unnecessarily prescriptive. Negotiated transmission services are subject to less invasive regulation, as there are fewer concerns for market failure.[204] The AER does not consider there is a need to specify terms and conditions to be included in an agreement for negotiated transmission services. Instead, arrangements for negotiated transmission services are appropriately to be settled through negotiation between two commercially able parties, and on a case by case basis.

7.5 AER determination

The negotiating criteria set out in appendix C will apply to VENCorp for the 2008 - 2014 regulatory control period. The negotiating criteria give effect to the negotiated transmission service principles contained in cl. 6A.9.1. All italicised terms should be interpreted as they are in the NER.

[202] AEMC National Electricity Amendment (Economic Regulations of Transmission Services) Rule 2006, No. 18, p xvii
[203] ibid.
[204] ibid.

The AER notes that the provisions of chapter 6A create a regime for the regulation of negotiated services which is intended to be less intrusive than the regime for prescribed services. This approach is premised on there being fewer market failure concerns in relation to negotiated services. In deciding on the negotiate/arbitrate regime, the AEMC considered that users of negotiated transmission services are likely to be large and well resourced, and possess countervailing market power enabling them to negotiate these services effectively.[205] As such, these services are not subject to the same upfront price control as prescribed transmission services in revenue determinations. Rather, they are the result of commercial agreement or, failing agreement, determined through commercial arbitration.

The AER will monitor the effectiveness of the negotiating criteria, and of the new framework, throughout the forthcoming regulatory period.

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[205] ibid., p. 41

8 Pricing methodology

8.1 Introduction

This chapter sets out the AER's consideration of VENCorp's proposed pricing methodology to apply for the forthcoming regulatory period.

In Victoria, VENCorp is responsible for pricing prescribed Transmission Use of System (TUOS) services and prescribed common transmission services, while SP AusNet sets prices for prescribed entry and exit services.[206]

8.2 Regulatory requirements

8.2.1 NER requirements

Clause 6A.24.1(b) of the NER defines a pricing methodology in terms of the pricing principles (as set out in rule 6A.23):

> A pricing methodology is a methodology, formula, process or approach that, when applied by a Transmission Network Service Provider:
>
> (1) allocates the aggregate annual revenue requirement for prescribed transmission services provided by that provider to:
>
> (i) the categories of prescribed transmission services for that provider; and
>
> (ii) transmission network connection points of Transmission Network Users; and
>
> (2) determines the structure of the prices that a Transmission Network Service Provider may charge for each of the categories of transmission services for that provider.

In accordance with cl. 6A.10.1(e), a TNSP's proposed pricing methodology must:

> (1) give effect to and be consistent with the Pricing Principles for Prescribed Transmission Services; and
>
> (2) comply with the requirements of, and contain or be accompanied by such information as is required by, the pricing methodology guidelines made for that purpose under rule 6A.25.

Clause 6A.14.3(g) requires the AER to approve VENCorp's proposed pricing methodology in its draft decision if it is satisfied that it meets the two requirements set out above. If the AER refuses to approve any aspect of VENCorp's proposed pricing methodology in its draft decision, cl. 6A.12.1(e) requires the draft decision to include details of the changes required or matters to be addressed before it will be approved.

Chapter 9 modifies the operation of part J of chapter 6A as it applies to VENCorp regarding the pricing for the provision of prescribed transmission services. Under cl. 9.8.4F, the allocation of the aggregate annual revenue requirement (under cl. 9.8.4C), and the allocation of transmission costs and the calculation of prescribed

[206] The pricing arrangements specific to Victoria are specified in cl. 9.8.4F of the NER. This derogation modifies the operation of part J of chapter 6A as it applies to VENCorp and SP AusNet.

transmission service charges (under part J) must reflect the arrangements in place in relation to the Victorian Transmission Network (or a part thereof) under the Electricity Industry Act 2000 (Vic), the Essential Services Commission Act 2001 (Vic) and the Tariff Order.

The AER developed transitional arrangements under cl. 11.8 of the NER (referred to as the ‘agreed interim requirements’) for those TNSPs required to submit their proposed pricing methodology before the AER published its pricing methodology guidelines under cl. 6A.25 in October 2007. Clause 11.8.4 specifies that the agreed interim requirements are to apply to VENCorp in place of the pricing methodology guidelines for the forthcoming regulatory period:

> For the purpose of making a 2008 pricing methodology, anything that must be done in accordance with the pricing methodology guidelines must instead be done in accordance with the agreed interim requirements.

8.2.2 Agreed interim requirements

After consulting with the relevant TNSPs, the AER released the agreed interim requirements on 16 February 2007. Clause 2.3(a) of the agreed interim requirements states:

> Within 10 business days of the AER publishing its pricing methodology guidelines under rule 6A.25 of the National Electricity Rules, the relevant provider may, by notice in writing to the AER, elect to have its proposed pricing methodology assessed against the pricing methodology guidelines instead of these agreed interim requirements.

Under the agreed interim requirements, if VENCorp makes an election to have its proposed pricing methodology assessed against the pricing methodology guidelines and, as a result of that assessment the AER refuses to approve its proposed pricing methodology, VENCorp must submit to the AER a revised proposed pricing methodology. This must be submitted to the AER within 10 business days of the AER publishing its draft decision. The resubmitted methodology must demonstrate consistency with the pricing principles in clause 6A.23 of the NER and the AER’s pricing methodology guidelines.

Clause 2.3(d) of the agreed interim requirements states that if VENCorp makes an election in accordance with clause 2.3(a) of the agreed interim requirements, it will then be subject to clause 2.3 and clause 2.4 of the agreed interim requirements only. Under these circumstances, the other provisions of the agreed interim requirements will cease to apply.

8.3 VENCorp’s proposal

VENCorp submitted its proposed pricing methodology to the AER on 12 June 2007, stating that it gives effect to and is consistent with the pricing principles in cl. 6A.23 and the agreed interim requirements. The proposed methodology outlines VENCorp’s interpretation of the agreed interim requirements and subsequently the pricing provisions in part C of the 'old' chapter 6[207] and those in part J of chapter 6A.

As co-ordinating TNSP for the Victorian region, VENCorp's proposed methodology notes that it is responsible for charging transmission customers for prescribed TUOS and prescribed common transmission services.

8.3.1 Allocation of MAAR to categories of prescribed transmission services

VENCorp notes that SP AusNet is responsible for determining the optimised replacement cost of its assets directly attributable to prescribed TUOS and prescribed common services, its Annual Service Revenue Requirement (ASRR) for these services and its opex incurred in the provision of prescribed common transmission services. VENCorp notes that SP AusNet will provide it with this information.

VENCorp states that it will determine the attributable cost shares of 'additional assets' directly attributable to the provision of shared network services that are operated and maintained by SP AusNet under its agreements with VENCorp. These assets will be attributed to prescribed TUOS services or prescribed common transmission services in accordance with schedule 6.2 of the old NER. VENCorp's ASRRs for these services will be added to SP AusNet's ASRRs.

VENCorp has an agreement under cl. 3.6.5(a)(5)(iii) with ElectraNet relating to settlements residue. These amounts will be applied to the non-locational component of TUOS. No corresponding agreement is in place between Victoria and NSW, however, if such an agreement were to arise, any payments or receipts would be applied to TUOS in the same manner.

VENCorp provides an example calculation of the ASRRs for prescribed TUOS and common transmission services for the Victorian region.

8.3.2 Allocation of the ASRR for prescribed TUOS services to connection points

VENCorp notes it will use the cost reflective network pricing (CRNP) methodology for determining the adjusted locational component of the ASRR for prescribed TUOS services and allocating this to connection points. It states that the adjusted locational component determined through this method will be 50% of the ASRR for prescribed TUOS services. VENCorp notes that an adjustment to the locational component is due to side constraints, and that this adjustment, and the determination of the locational component, must precede determination of the non-locational component.

VENCorp notes that it currently does not offer prudent discounts, but will make the necessary adjustments to non-locational component of the ASRR to prescribed TUOS should discounts be offered in the future.

[207] This refers to chapter 6 of 'version 9' of the NER, which was in force immediately before the commencement of the National Electricity Amendment (Economic Regulation of Transmission Services) Rule.

VENCorp provides an example (in the form of a hypothetical calculation) of the allocation of locational TUOS to connection points and of the non-locational component of the ASRR.

8.3.3 Price structures

VENCorp proposes to apply a capacity charge on the actual average demand for the 10 peak days during the summer period to recover the locational component of prescribed TUOS services. Forecast demand is used to calculate charges for the first nine months of the financial year (i.e. July to March) which are subsequently adjusted once actual demand data is available for the summer period.

VENCorp states that it will apply both demand and energy charges for the non-locational component of TUOS. Demand charges will apply to customers that have agreements with VENCorp specifying a contracted demand. Energy charges will be based on historical consumption data, or actual data where this is not available.

VENCorp states that it will develop both energy and capacity prices for prescribed common transmission services using a similar method for the non-locational component of TUOS services. These prices will be designed to recover:

- the ASRR for prescribed common transmission services
- SP AusNet’s opex incurred in providing these services to VENCorp
- VENCorp’s opex incurred in the provision of providing these services.

VENCorp provides an example calculation of prices for locational TUOS, non-locational TUOS and common services.

8.3.4 Equalisation adjustment

VENCorp is required to apply an equalisation adjustment to the shared transmission network charges it applies to the Victorian distribution network service providers under cl. 9.8.4(a)(3). VENCorp states that it will apply these values following calculation of prescribed TUOS and common services charges.

8.4 Submissions

The AER received no submissions on VENCorp’s proposed pricing methodology.

8.5 Issues and AER’s considerations

On 29 October 2007, the AER published its final pricing methodology guidelines. On 11 November 2007, VENCorp notified the AER that it wished to have its proposed pricing methodology assessed against the final pricing methodology guidelines. VENCorp’s election is permitted under clause 2.3(a) of the agreed interim requirements.

In accordance with the agreed interim requirements, VENCorp was required to ensure its proposed pricing methodology was consistent with the pricing principles in cl. 6A.23 of the NER. Additionally, its proposed pricing methodology was required to demonstrate consistency with part C of the old NER to the extent the provisions of part C were not inconsistent with the pricing principles in part J of the NER.

The final pricing methodology guidelines supplement and elaborate on the pricing principles insofar as they specify or clarify:

- the information that is to accompany a TNSP's proposed pricing methodology
- pricing structures for the recovery of the locational component of prescribed TUOS services
- permissible postage stamp pricing structures for the recovery of the non-locational component of prescribed TUOS services and prescribed common transmission services
- the types of transmission assets that are directly attributable to each category of prescribed transmission service
- the parts of a proposed pricing methodology, or the information accompanying it which will not be publicly disclosed without the consent of the TNSP.

VENCorp's proposed pricing methodology was developed under the agreed interim requirements and submitted to the AER prior to the release of both the draft and final pricing methodology guidelines.

The AER has assessed VENCorp's proposed pricing methodology against the final pricing methodology guidelines. While the key sections of the proposed pricing methodology, such as the pricing structures, comply with the requirements of the final pricing methodology guidelines, several areas do not, or require further explanation. As would be expected, these areas of non-compliance stem from references throughout the document to the agreed interim requirements and part C of the old NER that are no longer relevant for assessment under the AER's guidelines.

In addition to these references, several elements of VENCorp's proposed methodology will require elaboration against the information requirements specified in the pricing guidelines that were not specified under the interim agreed requirements. These include:

- an explanation of how the value of 'additional assets' will be calculated as it affects attributable cost shares (cl. 2.1(d)(1)(A))
- compliance with cl. 2.4 of the guidelines and the use of use of priority ordering approach outlined in cl. 6A.23.2(d) of the NER (cl. 2.1(d)(2))
- whether and how the proposed methodology differs from that currently in use (cl. 2.1(r))
- whether and how VENCorp will monitor its compliance with its methodology and with part J of the NER (cl. 2.1(s))
- whether the proposed methodology contains confidential or commercially sensitive information (cl. 2.5(b)).

VENCorp has made the election referred to in clause 2.3(a) of the agreed interim requirements and, for the reasons set out above, the AER is unable to approve its proposed pricing methodology. VENCorp must provide a revised proposed pricing methodology within 10 business days of the AER publishing its draft decision.

The AER will publish the revised proposed pricing methodology on its website and allow 30 business days for interested parties to make submissions.

8.6 AER's determination

The AER has assessed VENCorp's proposed pricing methodology against part J of the NER and the pricing methodology guidelines. Based on that assessment, the AER is unable to approve VENCorp's proposed pricing methodology.

VENCorp must submit to the AER a revised pricing methodology by 14 December 2007.

Appendix A: Forecast planned augmentation expenditure

This appendix presents the AER's detailed analysis of the sample of forecast planned augmentation projects reviewed as part of its assessment of VENCorp's forecast planned augmentation expenditure and charges for the forthcoming regulatory period.

As noted in chapter 4 of this draft decision, a sample of forecast augmentation projects from VENCorp's initial proposal was reviewed by PB Strategic Consulting (PB). When VENCorp submitted its reconciliation of the initial proposal with the 2007 EAPR in July 2007 (revised proposal), updated information in relation to the sample projects was provided. This information was not received in time for PB to treat the new information in its report to the AER, so the AER engaged Nuttall Consulting (NC) to assess the impact of the information provided in VENCorp's reconciliation on PB's recommendations in relation to the projects reviewed. The AER's consideration of the results of the detailed project reviews therefore takes into account both the initial proposal and the reconciliation, and the reports of both PB and NC.

The AER's consideration of each of the sample projects is structured as follows:

1. VENCorp's initial proposal
2. PB's review of VENCorp's initial proposal
3. VENCorp's reconciliation of its initial proposal and the 2007 EAPR
4. Nuttall Consulting's (NC) review of the impact of the reconciliation on PB's conclusions
5. The AER's consideration of the project in light of VENCorp's initial and revised proposals and the advice of its consultants.

A.1 1 000 MVA 500/200 kV transformer in the metropolitan area

A.1.1 VENCorp's initial proposal

VENCorp's initial proposal identifies the construction of a 1 000 MVA 500/200 kV transformer in the metropolitan area as a 'must do' project with a forecast cost of $43.8m ($2007–08), based on a preliminary feasibility estimate of $35m, to which VENCorp added a 25% cost multiplier. The forecast commissioning date in the initial proposal is prior to the summer period in 2012–13. This project is the equal largest expenditure item in VENCorp's forecast, and represents 12.4% of VENCorp's initial forecast planned augmentation expenditure.

The project involves the construction of a new transformer to increase the transformation capacity supplying the Melbourne metropolitan area.

A.1.2 PB's review

Noting that VENCorp's cost estimate is based on a simple desktop review and that, without further assessment on the part of VENCorp, the costing process is particularly theoretical, PB found that given the scope of works, the feasibility estimate of $35m was reasonable and prudent.[208] PB also noted that, for the purposes of its forecast of planned augmentation expenditure, VENCorp has applied a 25% cost multiplier. PB considered that the application of a 25% cost multiplier to the estimate of $35m to arrive at the total forecast of $43.8m was an inappropriate inclusion that should be removed.

While accepting that there was reason to examine the augmentation options available to alleviate any constraint on the metropolitan transformers, PB was unable to conclude on the basis of the information provided that VENCorp had established a clear need for the augmentation to be undertaken within the forthcoming regulatory period, or that the project is in fact likely to proceed within that period.[209] This conclusion was based on a detailed assessment of the load flow information provided by VENCorp in support of the forecast augmentation.

VENCorp has stated that the primary driver for this project is load growth, and that its need is not sensitive to the realisation of particular generation scenarios.[210] In support of its identified need, VENCorp provided the loadings for some of the key metropolitan transformers (Rowville and Cranbourne) under system normal, N–1 and N–2 conditions. VENCorp's analysis is based on the 2006 EAPR and assumes the 10% PoE conditions under the Latrobe Valley generation scenario.

PB made three key findings in relation to the load flow data presented by VENCorp:

- The load flow case used by VENCorp to represent summer 2013–14 reflects a Victorian demand level that is more consistent with the 10% PoE conditions forecast for *2014–15*, which leads PB to conclude that the timing in VENCorp's forecast is aggressive.
- The 10% PoE forecast is considerably higher than the 50% PoE conditions, such that the timing of the augmentation may be deferred by up to five years if modelled on the 50% PoE forecasts. Given VENCorp's treatment of these demand based scenarios as part of its planing criteria and historical project justifications, it is PB's opinion that any project timing based indicatively on the 10% PoE scenario alone will be materially advanced compared to the probabilistically weighted outcome that will flow from VENCorp's treatment of this project within the forthcoming regulatory period.
- Contrary to VENCorp's submission, PB found that the need for this project was influenced by the choice of generation scenario, with the Latrobe Valley scenario adopted for the purposes of VENCorp's forecast expenditure being the worst case scenario with respect to the transformer loadings. Given the equal weightings VENCorp has applied to all four of its generation scenarios, PB considered that

[208] PB Strategic Consulting, *VENCorp revenue reset – An independent review – Prepared for AER, 8 October 2007* p.71
[209] ibid., p. 69
[210] VENCorp. *VENCorp Electricity Revenue Cap Proposal 1 July 2008 to 30 June 2014, Explanation for planned augmentation program, Version 2.4*, p.14.

> there is a greater chance that the loading on the critical transformers will be reduced.[211]

PB recommended that no allowance be provided to VENCorp for the forecast metropolitan transformer project, because the prudent timing of this project is beyond the forthcoming regulatory period and the project is therefore unlikely to proceed within that period. PB considered the analysis presented by VENCorp in support of the advanced project timing to be very much a worst case scenario, and “not a reasonable reflection of an indicative probabilistic approach that closely aligns with VENCorp’s detailed application of its current planning criteria”.[212]

A.1.3 VENCorp’s revised proposal

The scope of the 1000 MVA 500/220 kV transformer in the metropolitan area project in the revised proposal does not differ from that outlined in the initial proposal. The 25% cost multiplier has been removed, giving a revised forecast cost of $35 million that reflects the original feasibility estimate. VENCorp’s revised forecast also defers the project by one year, from 2012–13 to 2013-14.

In VENCorp’s 2007 EAPR, the cost of the project remained unchanged, however, the commencement date in the 2007 EAPR was deferred to ‘approximately 2014’.

A.1.4 Nuttall Consulting’s review

NC is of the view that the revised proposal and the 2007 EAPR will not materially change or effect PB’s recommendations not to provide an allowance for the 1000 MVA 500/220 kV transformer in the metropolitan area project in the forthcoming regulatory period.

NC notes that VENCorp’s method of analysis in determining the timing for the 2007 EAPR had not changed from that applied in its initial proposal, and analysis is essentially based upon deterministic analysis of normal and outage network conditions, applying the maximum demand forecasts. These maximum demand forecasts have not changed substantially from those in the initial proposal, thus the results of the studies used in the EAPR would not significantly differ from those provided to PB during its review.[213]

NC found that VENCorp has not provided any new information in the EAPR which would change the basis of PB’s recommendations. The factors that supported PB’s recommendations were still relevant to any analysis of the 2007 EAPR.

NC also found that VENCorp’s deferral of the project in the 2007 EAPR to approximately 2014 has effectively validated PB’s concerns that the prudent timing of the project was likely to be later than 2012–13 due to the likely location of the new generation.[214] In this respect NC notes that the indicative probabilistic assessment in the 2007 EAPR is based on the results of the South West generation scenario studies,

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[211] PB, *op cit*, p.70
[212] ibid., p.71
[213] Nuttall Consulting, *op cit*, p.17
[214] ibid., p.18.

rather than the more onerous Latrobe Valley scenario assumed for the purposes of the expenditure forecast in VENCorp's initial proposal. VENCorp has stated that it considers the project date will be advanced to 2013–14 following a more detailed assessment, however NC does not consider that VENCorp has presented any information supporting why such a detailed assessment will advance the optimal date for the project any more than confirm PB's view. Assuming the approximate timing of 2014 in the 2007 EAPR contemplated commissioning in time for summer 2013–14 (consistent with the forecast within-year timing presented in VENCorp's initial proposal), NC does not consider that there is reason to vary PB's conclusion that the timing of this project is likely to fall outside the forthcoming regulatory period.

A.1.5 AER's considerations

The AER agrees with PB's finding that, while there is a need for transformer capacity augmentation, and consideration of options is appropriate at this time, the information presented by VENCorp does not support its proposed inclusion of an allowance for this project in forecast for the forthcoming regulatory period. On the balance of the information provided it has not been demonstrated that the need for the metropolitan transformer project will arise in the forthcoming regulatory period. On the basis that the project seems unlikely to proceed before the conclusion of the forthcoming regulatory period, the AER is not satisfied that the forecast expenditure reasonably reflects a realistic expectation of the costs that VENCorp will require in that period. Nor is the AER satisfied that this forecast expenditure reasonably reflects efficient costs that a prudent operator would require to achieve the capex objectives in cl. 6A.6.7(a) of the NER.

The AER is concerned at the lack of documentation provided by VENCorp to support the need and timing for the forecast augmentation, and the appropriateness of its inclusion in a forecast of expenditure for the forthcoming regulatory period, especially given the considerable cost of this project. Also of concern is the limited assessment of alternatives undertaken by VENCorp. In this respect, the AER notes that the forecast commissioning date of the project is not until late in the period, which may help to explain why only a lower level of analysis had been undertaken.

On the basis of NC's analysis of the revised proposal and the 2007 EAPR, the AER does not consider that the new information provided by VENCorp materially changes or effects PB's recommendations not to provide an allowance for this project in the forecast expenditure for the forthcoming regulatory period.

The AER therefore concludes that no allowance should be provided to VENCorp for expenditure on the forecast metropolitan transformer augmentation in the forecast planned augmentation charges for the forthcoming regulatory period.

Table A.1: AER's draft decision — 1 000 MVA 500/200kV transformer in the metropolitan area ($m, 2007–08)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Initial proposal	–	–	–	–	43.8	–	43.8
Initial proposal (ex 25%)	–	–	–	–	35.0	–	35.0
PB's recommendation	–	–	–	–	–	–	–
Revised proposal	–	–	–	–	–	35.0	35.0
NC's recommendation	–	–	–	–	–	–	–
AER's draft decision	**–**	**–**	**–**	**–**	**–**	**–**	**–**

Source: Nuttall Consulting and AER analysis.

A.2 Minimum reactive support in the state grid

A.2.1 VENCorp's initial proposal

VENCorp identifies minimum reactive support in the state grid as a 'must do' project with a cost of $10m ($2007–08) allocated evenly across the final four years of the forthcoming regulatory period, representing 2.8% of VENCorp's forecast planned augmentation expenditure.

This element of VENCorp's forecast of planned augmentation expenditure is not in the nature of a typically scoped project. Rather, it is presented as a general allowance that is highly dependent on the amount of new generation installed in regional Victoria. The forecast expenditure underlying this allowance consists of the staged installation of shunt capacitor banks across a number of locations in the state grid. Shunt capacitor banks are a source of reactive support and are used to maintain voltage levels in the state grid at period of high demand.

A.2.2 PB's review

PB noted that VENCorp did not present any specific technical or economic studies to justify either the need or timing of the forecast expenditure covered by this allowance. Nor did it present any precedent expenditure in support of its forecast. PB did not consider that VENCorp has demonstrated the technical or economic benefits that may accrue from the forecast expenditure.

PB also noted that, while in the current period there has been a significant deferral of the need for the installation of capacitors due to the completion of several other projects, VENCorp has not in this case demonstrated consideration of how the multiple reactive support projects in its forecast will impact on one and other, or on the need for the expenditure included in this forecast general allowance.

Due to the lack of evidence justifying the composition and level of this forecast expenditure, PB recommended a general allowance be made for the cost of one capacitor bank in the state grid, in the amount of $2m, allocated to the final year of the regulatory period.

A.2.3 VENCorp's revised proposal

In its revised proposal, VENCorp defined the scope of works underlying this general allowance as the installation of 150 MVAr of capacitor banks in the state grid, covering the installation of one bank of 2 x 25 MVAr 66 kV shunt capacitors in each of the 2010–11, 2011–13 and 2013–14 financial years. The cost in the revised proposal is $7.5m (down from $8m in the initial proposal) and no longer includes the 25% cost multiplier applied in the initial proposal. The cost of the 2 x 25 MVAr bank was increased in the revised proposal from $2.3m to $2.5m. The basis of this cost increase was a 10% "rule of thumb" cost extrapolation applied by VENCorp.

VENCorp did not discuss the nature of the works included in this allowance in any detail in its 2007 EAPR, simply stating that reactive support in the state grid was primarily 'needs driven'.

A.2.4 Nuttall Consulting's review

In NC's opinion, the revised proposal and 2007 EAPR do not contain any information that is significantly different to that in the initial proposal, and does not materially impact on PB's recommendations on the prudent and efficient scope of this allowance. While VENCorp has indicated in discussions with the AER and its consultants that further analysis has been undertaken since the initial proposal, NC sees no evidence that this is substantially different to that underlying the initial proposal such that it would address PB's concerns.

NC does, however, recommend that PB's recommended allowance of $2m for the installation of one 2 x 25 MVAr capacitor bank in 2013-14 should be revised to $2.34m:

- NC does not accept that the further 10% increase to $2.5m that VENCorp applied in its revised proposal is justified. As NC notes, the 10% increase has been applied by VENCorp following increases in other project cost estimates provided to VENCorp by SP AusNet during the 2007 EAPR process. However, according to NC the basis for SP AusNet's increases in its revised project costs for other projects is not appropriate for this general allowance. Original cost estimates were derived from actual contract costs from recent contestable projects. Therefore, NC concludes that it would be expected that cost estimations would intrinsically allow for brownfield costs.[215]
- NC has instead applied the cost escalation data used by the AER in its draft decision on SP AusNet. Original cost estimates are assumed to be based on December 2006 prices (as informed by VENCorp), and when the forecast timing is taken into account, the escalation data demonstrates a total increase of 1.9% is appropriate. This has been applied to VENCorp's original cost of $2.3m for the capacitor banks to determine an efficient forecast cost of $2.34m.

[215] ibid., p.21

A.2.5 AER's considerations

The AER agrees with PB's comments regarding the lack of justification for the forecast expenditure underlying this allowance. The AER is concerned by the apparent lack of integration between the projects put forward by VENCorp in its revenue proposal, and its apparent lack of consideration of the displacement of forecast expenditure covered by the equivalent allowance over the current regulatory period. This lack of a systematic and coordinated approach appears to lead to an overstatement of the level of augmentation expenditure likely to be incurred by VENCorp over the forthcoming regulatory period.

On the balance of the information provided, the AER is not satisfied that the expenditure VENCorp has forecast under the banner of this general allowance reflects prudent and efficient expenditure that will be required in the forthcoming regulatory period to meet the objectives set out in the NER, or a realistic expectation of the cost inputs required to do so. In the absence of any substantive information demonstrating the need for the allowance as defined by VENCorp in its initial proposal or its revised proposal, the AER accepts the basis for PB's recommended reduction.

In applying PB's recommended reduction, the AER has accepted NC's recommended allowance of $2.34m, as calculated using cost escalation data from the AER's draft decision on SP AusNet.

Table A.2: AER's draft decision — Minimum reactive support in the state grid area ($m, 2007–08)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
Initial proposal	–	–	2.5	2.5	2.5	2.5	10.0
Initial proposal (ex 25%)	–	–	2.0	2.0	2.0	2.0	8.0
PB's recommendation	–	–	–	–	–	2.0	2.0
Revised proposal	–	–	2.5	2.5	–	2.5	7.5
NC's recommendation	–	–	–	–	–	2.34	2.34
AER's draft decision	**–**	**–**	**–**	**–**	**–**	**2.34**	**2.34**

Source: Nuttall Consulting and AER analysis.

A.3 Line terminations and monitoring equipment in the metropolitan area

A.3.1 VENCorp's initial proposal

VENCorp identifies line terminations and monitoring equipment in the metropolitan area as a 'must do' project with a cost of $19m ($2007–08), allocated evenly across the final five years of the forthcoming regulatory control period. The forecast allowance represents 5.3% of VENCorp's forecast planned augmentation expenditure.

As in the case of VENCorp's forecast of expenditure on minimum reactive support in the state grid area, this component of VENCorp's forecast is not a project with a defined scope of works, and is again in the nature of a general, non-prescriptive allowance for unspecified, needs driven works. The forecast expenditure underlying this allowance consists of the staged installation of primary and secondary equipment across a number of locations to alleviate operational thermal constraints. Thermal ratings of various assets can impact on the overall transfer capacity between two points on the network.

A.3.2 PB's review

PB noted that VENCorp has not provided any specific technical studies to support the need for this forecast expenditure, which VENCorp states is to alleviate operational thermal constraints that arise with general load growth. PB found that VENCorp has not undertaken an analysis of alternative options to address potential constraints, and has simply inlcuded a non–prescriptive allowance in its forecast:

> VENCorp advises that the detailed application of its planning criteria and the application of the market benefits limb of the Regulatory Test, ensure that the 'do-nothing' option will prevail until a network alternative returns a higher market benefit.[216]

PB identified several other projects within both VENCorp's and SP AusNet's revenue proposals that may impact on the need to undertake piecemeal augmentation to alleviate operational thermal constraints.[217] PB concluded that VENCorp does not appear to have considered the interactions of these other projects and will therefore have materially overstated its expenditure requirements.[218]

However, given the past need to undertake piecemeal augmentation to alleviate thermal constraints, PB considered that it is foreseeable that there will be some need for such augmentation in the future. Having regard to historical levels of expenditure for similar works, PB recommended the forecast allowance be reduced by 50% to account for VENCorp's lack of recognition of SP AusNet's replacement works. PB considered this reduction to be conservative given the extent of SP AusNet's proposed capital works program and the fact that VENCorp:

- has separately identified some prescriptive upgrades in the metropolitan area
- has already undertaken a number of similar metropolitan upgrades in recent years
- has identified that forecast load growth over the forthcoming period is less than that over the current period, and
- has not specifically identified any piece of equipment that needs to be augmented under the auspices of this allowance, even in the earliest years of the forthcoming period.

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[216] PB Strategic Consulting, *op cit,* p. 76
[217] These projects include the six metropolitan terminal stations that SP AusNet has proposed to rebuild in the forthcoming regulatory period and other targeted replacement programs such as those for circuit breakers and current transformers.
[218] PB Strategic Consulting, *op cit*, p. 77

A.3.3 VENCorp's revised proposal

The estimated cost of the forecast line terminations and monitoring equipment in the metropolitan area in VENCorp's revised proposal is $15m. There has been no change in the underlying costs estimate other than the removal of the 25% cost multiplier.

A.3.4 Nuttall Consulting's review

NC notes that neither the revised proposal, nor the 2007 EAPR provide much detail in relation to this allowance, and that both simply state that it is "needs driven".[219] Certainly there is no additional information provided in the revised proposal or the 2007 EAPR in relation to this allowance, and as such no new information that could be considered to counter PB's recommendations.

NC notes that there has been no change in the scope and forecast expenditure underlying this general allowance (other than the removal of the 25% cost multiplier) between VENCorp's original and revised proposals. Therefore, NC is of the opinion that the revised proposal and 2007 EAPR will not materially affect PB's recommendations.[220]

A.3.5 AER's considerations

The limited information presented to support the need for this forecast expenditure, coupled with VENCorp's inability to justify its forecast level of expenditure, leaves the AER unable to conclude on balance that the forecast allowance reflects expenditure that would be required by a prudent and efficient TNSP in order to meet the expected demand for prescribed transmission services over the forthcoming regulatory period. The AER notes the similar lack of scoping undertaken by VENCorp to substantiate the equivalent 'Miscellaneous Works' allowance in its 2002 Revenue Cap application to the ACCC, which it stated represented provision for "unidentified works that are generally less than $1m. For example, protection, control and termination equipment upgrades…".[221]

The AER notes PB's comment that piecemeal upgrades of limiting plant (as would be covered by this allowance) can economically reduce the impacts of some transmission constraints. VENCorp's historical expenditure tends to suggest that some allowance of this nature in VENCorp's forecast of expenditure is reasonable to accommodate such work.

The AER accepts NC's recommendations that the revised proposal and 2007 EAPR will not materially affect PB's recommendations on the efficient and prudent level of expenditure. In the absence of detailed studies supporting VENCorp's forecast, the AER accepts PB's reduction of 50%, which results in an allowance more reflective of past levels of expenditure. The AER agrees with PB's reasoning that this is a conservative reduction, as VENCorp appears to have developed its forecast without regard to any impact that other projects (whether initiated by VENCorp or SP AusNet) may have on the need for this allowance.

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[219] Nuttall Consulting, *op cit*, p. 24
[220] ibid.
[221] VENCorp, *ACCC Electricity Revenue Cap Application 2003–2008*, p. 32

The AER therefore concludes that an allowance of $9.5m, spread evenly over the final five years of the forthcoming regulatory period, reasonably reflects a prudent and efficient level of expenditure, and a realistic expectation of the cost inputs that will be required to meet the capex objectives in the forthcoming regulatory period.

Table A.3: AER's draft decision — Line terminations and monitoring equipment in the metropolitan area ($m, 2007–08)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
Initial proposal	–	3.8	3.8	3.8	3.8	3.8	19.0
Initial proposal (ex 25%)	–	3.0	3.0	3.0	3.0	3.0	15.2
PB's recommendation	–	1.9	1.9	1.9	1.9	1.9	9.5
Revised proposal	–	3.0	3.0	3.0	3.0	3.0	15.0
NC's recommendation	–	1.9	1.9	1.9	1.9	1.9	9.5
AER's draft decision	**–**	**1.9**	**1.9**	**1.9**	**1.9**	**1.9**	**9.5**

Source: Nuttall Consulting and AER analysis.

A.4 Fourth 330/220 kV transformer at Dederang terminal station

A.4.1 VENCorp's initial proposal

In its initial proposal VENCorp identifies the installation of a fourth 330/220 kV transformer at Dederang as a 'generation scenario driven' project with a cost of $13.8m ($2007–08), allocated evenly across the final four years of the forthcoming regulatory period. The project represents 3.9% of the forecast of planned augmentation expenditure in VENCorp's initial proposal.

The project involves the augmentation of transformer capacity at the Dederang terminal station (DDTS) through the installation of a fourth 330/220 kV transformer. DDTS is located in the north east of Victoria and is a critical link in the supply to northern Victoria.

A.4.2 PB's review

In its initial revenue proposal, VENCorp included this project in its forecasts for all four generation scenarios. Following questioning from PB, VENCorp identified this as an error, and removed the project from three of the scenarios, leaving it only in the increased Snowy/NSW import scenario. This reduction in probability reduced the proposed forecast of expenditure by 75%, from $13.8m to $3.45m. This change is set out in table A.4.

In support of the need for this project, VENCorp presented several load flow analyses under varying system conditions. PB analysed this preliminary technical information and concluded that it does not present a clear need for the installation of a fourth transformer at DDTS. While PB considered that the constraint to which this forecast augmentation is directed is apparent, it was unable to conclude that a solid indicative probabilistic business case for the installation of a fourth transformer was evident.

While in practice VENCorp's detailed application of the market benefits limb of the regulatory test, coupled with VENCorp's use of a Value of Customer Reliability, will implicitly include a 'do nothing' option until a network alternative returns a higher positive market benefit, PB noted that VENCorp has not presented any network or non-network alternatives against which its proposal to install a fourth transformer might be assessed.

Further, PB commented that VENCorp has not clearly indicated if or how it has coordinated its forecast of augmentation requirements at DDTS with SP AusNet, which in its forecast of capex for the forthcoming regulatory control period proposes replacement of the oldest transformer at DDTS in the forthcoming regulatory period.

> In PB's view the replacement of the H1 unit and the installation of a fourth unit are not independent projects. Replacement of the H1 unit with a higher capacity transformer is likely to capture efficiencies for both parties and be the most efficient single project.[222]

On the basis of the information provided by VENCorp, PB considered that there was insufficient evidence of the need for transformer capacity augmentation at DDTS. However, having also considered SP AusNet's proposal to replace one of the aging units at DDTS, PB considered that there is likely scope to consider a combined replacement/augmentation project towards the end of the forthcoming regulatory period.

On the basis that both SP AusNet and VENCorp will receive some benefit from a coordinated project, PB considered that it would be prudent to provide 50% of the cost of replacing the H1 transformer to each party. PB therefore recommended the inclusion of an alternative allowance of $5m in place of VENCorp's forecast expenditure on the installation of the fourth transformer.

PB concluded that the most likely timing of its recommended alternative will be prior to summer 2012–13, when an increase in import from NSW is most likely.

A.4.3 VENCorp's revised proposal

The cost of the fourth 330/220 kV transformer at Dederang project was substantially increased in the revised proposal from $13.8m to $21m, even though it no longer included the 25% adjustment to the feasibility estimate of $11m applied in VENCorp's initial proposal.

The revised costs match those in VENCorp's 2007 EAPR, which are based on a revised estimate for this specific project provided by SP AusNet in May 2007. The functional scope of the project has not changed significantly between VENCorp's

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[222] PB Strategic Consulting, *op cit*, p.81.

initial and revised proposals, however the revised proposal includes a double switched 330 kV bay in place of a single switched bay in the initial proposal.

A.4.4 Nuttall Consulting's review

NC concludes that the revised proposal and the 2007 EAPR do not have a material impact in relation to PB's recommendation regarding the need to install a fourth transformer at DDTS in the forthcoming regulatory period, and concludes that PB's recommendation to not provide any allowance for this project is unaffected. However, for the purposes of the AER's consideration, NC reviewed the basis for the significant increase in SP AusNet's estimate of the costs of the forecast augmentation, and the minor scope change.

NC notes that although there has been a substantial increase in the cost estimate for this project from that in VENCorp's initial proposal, there has been minimal change to its functional scope.

The revised cost estimate for this project was supplied by SP AusNet, and increased by 90%, from $11 million to $21 million. SP AusNet advised VENCorp that the original estimate was an indicative 'greenfield' estimate based on pricing data from 2000–2004 projects, whereas the revised estimate includes 'brownfield' factors and more up to date plant, equipment and construction costs.

After conducting its own cost analysis, NC concluded that the original cost estimate of $11m was too low, and that SP AusNet's revised cost estimate appeared reasonable in the broad context of the EAPR for which it was provided. However, NC did not consider that the revised cost estimate reflected likely prices at the forecast timing of the project. Noting data presented in the AER's recent draft decision on SP AusNet, which suggests that while costs have increased significantly since 2002 they are likely to peak in real terms in 2007-08 and decrease by the end of the forthcoming regulatory period, NC estimates that the cost of the project at the time suggested in VENCorp's proposal is likely to be $19m ($2007-08).

NC also concluded that the information in VENCorp's revised proposal and the 2007 EAPR did not justify the minor change in the forecast functional scope of the project, and recommended a further reduction of $1.2m to allow for the single switched 330 kV arrangement contemplated in VENCorp's initial proposal.

A.4.5 AER's considerations

The AER notes that VENCorp has revised its initial proposal by removing this project from three of the four generation scenarios in which it was originally included, and has based its considerations on the corrected (weighted by 25%) forecast of costs that results from this adjustment. The AER agrees with PB's finding that, while recognising the constraints at DDTS and the loadings on the three transformers currently installed at DDTS, VENCorp has not established a clear need to install a fourth transformer at DDTS to address those constraints.

The AER accepts NC's conclusion that the revised proposal and 2007 EAPR do not materially affect PB's recommendations.

On the basis of PB's advice, the AER considers that there may be a case for alleviation of this constraint through the augmentation of the aging third transformer at DDTS, and will therefore provide VENCorp with an efficient allowance to undertake this work. In determining an efficient allowance, the AER has used SP AusNet's forecast cost of replacing the third transformer which, while not justified on a replacement-only basis, as an augmentation option appears in terms of prudency and efficiency to represent a reasonable solution to the identified constraint. The AER therefore considers that the SP AusNet cost estimate of $9.9m represents an efficient cost for the replacement of the H1 transformer at Dederang. Noting that the need for augmentation arises in only one scenario, the AER has included a revised (weighted) forecast of $2.48m.

Table A.4: AER's draft decision — 4th 330/22kV transformer at Dederang terminal station ($m, 2007–08)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
Project cost							
Initial proposal							13.8
Initial proposal (ex 25%)							11.0
PB recommendation							5.0
Revised proposal							21.0
Weighted contribution to expenditure							
Initial proposal	–	–	3.45	3.45	3.45	3.45	13.80
Initial proposal (ex 25%)	–	–	2.76	2.76	2.76	2.76	11.04
PB's recommendation	–	–	–	–	5.0	–	5.0
Revised proposal	–	–	1.31	1.31	1.31	1.31	5.25
NC's recommendation	–	–	–	–	5.0	–	5.0
AER's draft decision	**–**	**–**	**0.62**	**0.62**	**0.62**	**0.62**	**2.48**

Source: Nuttall Consulting and AER analysis.

A.5 Fourth 500 kV line Loy Yang to Hazelwood

A.5.1 VENCorp's proposal

In its initial proposal VENCorp identifies the fourth 500 kV line from Loy Yang to Hazelwood as a 'generation scenario driven' project with a cost of $37.5m ($2007–

08), allocated evenly across the final four years of the forthcoming regulatory period. Appearing in two out of four scenarios, when weighted the project represents 5.3% of VENCorp's initial forecast of planned augmentation expenditure.

The project involves the construction of a fourth line between Loy Yang power station switchyard (LYPS) and Hazelwood terminal station (HWTS) and associated switching equipment. Located in the Latrobe Valley, HWTS is the key aggregating station for the Latrobe Valley generators.

A.5.2 PB's review

PB concluded that VENCorp has demonstrated a clear need for the LYPS to HWTS augmentation given the extent of the potential overloads presented and the dependence on Latrobe Valley generation supplies in peak conditions. Should new generation be connected at the 500 kV level at Loy Yang, PB considered that there will be a clear need for the augmentation, especially if the new generation is a base load unit with a high load factor.[223]

PB considered the 25% cost multiplier applied by VENCorp to reach its initial forecast of $37.5m was inappropriate, but concluded that, while on the high side, the underlying cost estimate of $30m was a reasonable and efficient allowance for the forecast scope of the project.[224]

However, in proposing to include two 500 kV circuit breakers at Hazelwood, PB considered VENCorp's forecast scope of works to be inefficient when there was a clear opportunity to implement the project using only a single circuit breaker. PB concluded that the efficient scope of the project would involve single switching the line at Hazelwood, rather than the double switching proposed by VENCorp. PB therefore recommended a reduction in the forecast cost of $2m to account for the removal of one 500 kV circuit breaker from the project scope, noting that this will not result in any material reduction in the functional or operational performance of the assets.

A.5.3 VENCorp's revised proposal

While VENCorp's original proposal included in both the Latrobe Valley and Import scenarios, VENCorp's revised proposal only includes this project in the Latrobe Valley scenario. While the 25% cost multiplier in the initial proposal has been removed, the estimated cost of the project has increased from $37.5m in the initial proposal to $45m in the revised proposal, without any significant changes to the functional scope.

The weighted contribution of this project to VENCorp's forecast planned augmentation expenditure is $11.25m (25% of the total forecast project cost).

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[223] PB Strategic Consulting, *op cit*, p.84.

A.5.4 Nuttall Consulting's review

The original estimate of the Hazelwood project is also based upon an SP AusNet estimate. PB in its cost benchmarking of the initial proposal was of the view that the costs were reasonable, and on the high side.

VENCorp applied a "rule of thumb" cost extrapolation of 50%, based indirectly on a revised cost estimate received from SP AusNet in relation to a different project. NC is of the view that the project to which this other cost estimate pertains (the stringing of a second 220 kV circuit on an existing line) has a different scope of work to the Loy Yang to Hazelwood line project, making it an inappropriate basis for attempting to forecast any price increase in relation to this project. As such, NC does not consider VENCorp's "rule of thumb" cost extrapolation to be suitable or appropriate.

NC does accept, however, that some increase to the cost estimate in the initial proposal is likely to be warranted. NC forecast the cost increase from the original project costs using the escalation data applied by the AER in its draft decision on SP AusNet's transmission determination. To calculate the appropriate increase in real $2007–08 terms to the original cost, NC has assumed the original cost is based on 2002–2004 prices, and the project timing is assumed to be equally likely in the last four years of the next period, as proposed by VENCorp for the purposes of its forecast.[225] NC has also allowed for brownfield factors for the substation (but not the lines) component of the project cost. These calculations produce a revised cost of $37.74m on the basis of VENCorp's recommended project scope.

NC notes that there is no information in the 2007 EAPR or VENCorp's revised proposal to confirm or counter PB's view that VENCorp's forecast project scope was inefficient and that the forecast project cost should be reduced by $2m to remove the unnecessary cost of double-switching at Hazelwood. On the assumption that PB's estimate of the $2m adjustment already allows for appropriate price escalations, NC advises that an efficient cost for this project, accounting for PB's recommendation on scope and the project cost increases already discussed, is calculated to be $35.74m.

A.5.5 AER's considerations

The AER considers that there is an identified need for the fourth 500 kV line between LYPS and HTS during the forthcoming regulatory period should the Latrobe Valley generation scenario eventuate. The AER agrees with PB's view that the commissioning of new generation upstream of the Loy Yang to Hazelwood 500 kV lines would result in the need for further capacity between these two stations.

The AER also accepts PB's recommendation regarding the scope of the project, and that the removal of one 500 kV circuit breaker is necessary to eliminate the inefficiency in VENCorp's forecast project scope, and take into account the efficient alternative. Accordingly, the AER considers an adjusted forecast of $35.74m (weighted to $8.94m) is an efficient allowance for the LYPS to HWTS augmentation, and reasonably reflects an efficient cost that a prudent operator would incur in achieving the capex objectives.

[225] Nuttall Consulting, *op cit*, p.36.

Table A.5: AER's draft decision — Fourth 500kV line Loy Yang to Hazelwood ($m, 2007–08)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Total
Project cost							
Initial proposal							37.50
Initial proposal (ex 25%)							30.00
PB recommendation							28.00
Revised proposal							45.00
Weighted contribution to expenditure							
Initial proposal	–	–	4.69	4.69	4.69	4.69	18.75
PB's recommendation	–	–	3.50	3.50	3.50	3.50	14.00
Revised proposal	–	–	2.81	2.81	2.81	2.81	11.25
NC's recommendation	–	–	2.23	2.23	2.23	2.23	8.94
AER's draft decision	**–**	**–**	**2.23**	**2.23**	**2.23**	**2.23**	**8.94**

Source: Nuttall Consulting and AER analysis.

Appendix B: Changes required to VENCorp's negotiating framework

As required by cl. 6A.12.1(d) of the NER, this appendix sets out the changes required and matters to be addressed before VENCorp's proposed negotiating framework will be approved by the AER. Required changes are shown in **bold**.

…

VENCorp Proposed Negotiating Framework 2008-09 – 2013-14

Negotiating Framework for Electricity Negotiable Services

This document sets out VENCorp's negotiating framework for the purposes of clause 6A.9 of the National Electricity Rules, and forms part of VENCorp's *transmission determination* for the period 1 July 2008 to 30 June 2014. The terms used in this document are defined in the National Electricity Rules.

1. Negotiation in good faith and reasonable endeavours to adhere to time periods

VENCorp and a *Service Applicant* shall negotiate in good faith *the terms and conditions of access* for the provision of *negotiated transmission services* under this framework and use reasonable endeavours to commence, progress and finalise negotiations in a timely manner. Where the *negotiated transmission services* sought by the *Service Applicant* relate to *connection,* VENCorp will comply with any applicable time periods required under clause 5.3 of the National Electricity Rules.

2. VENCorp and Service Applicants to provide information

Subject to any confidentiality obligations owed by either VENCorp or *Service Applicant* to any third party:

- VENCorp will provide all such commercial information as a *Service Applicant* may reasonably require to enable the *Service Applicant* to engage in effective negotiation with VENCorp for the provision of negotiable services; *negotiated transmission services,* including a description of the nature of the *negotiated transmission service* and details of what VENCorp would provide as part of that service; and
- A *Service Applicant* shall provide all such commercial information as VENCorp may reasonably require enabling VENCorp to engage in effective negotiation with the *Service Applicant* for the provision of *negotiated transmission services* including a detailed description of the negotiable service required.

3. Confidentiality

Each of VENCorp and a *Service Applicant* shall observe any confidentiality restrictions placed on commercial information provided to it by the other party under paragraph 2, in accordance with clause 6A.9.6(a)(12) or (b)(2) of the National Electricity Rules. This obligation:

- shall not apply to the extent that VENCorp or the *Service Applicant* is required to disclose the confidential information under any law, Rules or regulation, or any requirement of a Government Minister or body; and
- does not limit any obligations of VENCorp and any *Service Applicant* under clause 5.3.8 of the National Electricity Rules.

4. Cost of the negotiated transmission services

VENCorp shall inform a *Service Applicant* of the reasonable costs, or change in costs, of VENCorp providing *negotiated transmission services* to the *Service Applicant,* and shall demonstrate to the *Service Applicant* that these reflect the costs, or change in costs, of VENCorp providing the *negotiated transmission services*.

5. Dispute Resolution

All disputes concerning negotiations for *negotiated transmission services* shall be dealt with in accordance with part K of chapter 6A of the National Electricity Rules.

6. Payment of VENCorp’s direct expenses

A *Service Applicant* shall pay VENCorp’s direct expenses incurred in processing its application for *negotiated transmission services*. Those expenses must be reasonable and are payable by a *Service Applicant* upon application.

Generally, VENCorp will require a *Service Applicant* to pay a fee on application on account of VENCorp's anticipated reasonable direct expenses associated with processing the application to provide *negotiated transmission services*. This application fee will be a minimum of $15,000. **In the event that VENCorp's reasonable expenses are less than the application fee paid by the *Service Applicant*, VENCorp will refund or credit the difference to the *Service Applicant*.**

7. Potential impact on other Network Users

VENCorp will determine the potential impact on other *Transmission* Network Users of provision of a *negotiated transmission service*. VENCorp will notify and consult with any affected *Transmission* Network Users to ensure that the provision of a *negotiated transmission service* does not result in non-compliance with obligations in relation to those *Transmission* Network Users under the National Electricity Rules or under contractual arrangements with VENCorp.

9. VENCorp and Network User to comply with Framework

VENCorp and Service Applicant shall comply with the terms of this negotiating framework when negotiating for the provision of a negotiated transmission service. However, in the event of any inconsistency between this framework and the requirements of chapters 4, 5 or 6A of the National Electricity Rules, those requirements will prevail over the relevant terms of this framework.

Appendix C: Negotiated transmission service criteria

National Electricity Market Objective

1. The *terms and conditions of access* for a *negotiated transmission 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 *market* objective.

Criteria for terms and conditions of access

Terms and Conditions of Access

2. The *terms and conditions of access* for a *negotiated transmission service* must be fair and reasonable and consistent with the safe and reliable operation of the power system in accordance with the NER.
3. The *terms and conditions of access* for a *negotiated transmission 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 the TNSP and the other party, the price for the *negotiated transmission service* and the costs to the TNSP of providing the *negotiated transmission service*.
4. The *terms and conditions of access* for a *negotiated transmission 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.

Price of Services

5. The price for a *negotiated transmission service* must reflect the costs that the TNSP has incurred or incurs in providing that service, and must be determined in accordance with the principles and policies set out in the *Cost Allocation Methodology*.
6. Subject to criteria 7 and 8, the price for a *negotiated transmission service* must be at least equal to the avoided cost of providing that service but no more than the cost of providing it on a stand alone basis.
7. If the *negotiated transmission service* is a *shared transmission 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 transmission service* which meets network performance requirements must reflect the TNSP's incremental cost of providing that service.

8. If the *negotiated transmission service* is the provision of a *shared transmission 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 transmission service* which meets, but does not exceed, the network performance requirements should reflect the amount of the TNSP's avoided cost of providing that service.

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

10. The price for a *negotiated transmission 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 is being recovered through charges to that other person.

11. The price for a *negotiated transmission service* must be such as to enable the TNSP to recover the efficient costs of complying with all regulatory obligations associated with the provision of the *negotiated transmission service*.

Criteria for access charges

Access Charges

12. Any *access charges* must be based on costs reasonably incurred by the TNSP in providing *Transmission Network User* access and (in the case of compensation referred to in clauses 5.4A (h) to (j)) on the revenue that is likely to be foregone and the costs that are likely to be incurred by a person referred to in rule 5.4A (h)-(j) where an event referred to in those paragraphs occurs.

Glossary

$/Mwh	dollars per megawatt hour
$2007-08	real 2007-08 dollars
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AIS	availability incentive scheme
ASRR	Annual Service Revenue Requirement
capex	Capital expenditure
cl.	clause
CPI	consumer price index
CRNP	cost reflective network pricing
DDTS	Dederang terminal station
EAPR	Electricity Annual Planning Report
EUCV	Electricity Users Coalition of Victoria
FTE	full-time equivalent
HWTS	Hazelwood terminal station
IFRS	international financial reporting standards
kV	Kilo volt
m	Million
MAAR	Maximum allowable aggregate revenue
MAR	maximum allowed revenue
MNSP	Market network service provider

MVAr	Mega volt ampere
MW	Mega watt
Mwh	megawatt hour
NC	Nuttal Consulting
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NIEIR	National Institute of Economic and Industry Research
NTSC	Negotiated transmission service criteria
opex	operating expenditure
PB	PB Strategic Consulting
PoE	Probability of exceedence
RAB	Regulatory asset base
TNSP	Transmission service network provider
TUOS	transmission use of system
VENCorp	Victorian Energy Networks Corporation
Vic	Victoria
WACC	Weighted average cost of capital