

may reduce the incentive to undertake only efficient capex and opex in some circumstances. An appropriate uncertainty regime will contribute to efficiency of investment by allocating risks to the party best able to deal with them, including appropriately sharing the risks of external events.

### **Capex reopeners and contingent projects**

Contingent projects and capex reopeners are not currently included under Chapter 6 for distribution. This was because the MCE Standing Committee of Officials (SCO) considered when developing Chapter 6 that distribution projects were different to transmission with respect to their nature and profile of capex, with uncertainty around certain capex projects to be dealt with via pass through provisions, and the objective that this would strike a reasonable balance between not penalising the DNSP for events outside its control and ensuring appropriate operation of the incentives regime within the regulatory framework.<sup>385</sup>

The AER proposed to include capex reopener and contingent project provisions in Chapter 6 of the NER.<sup>386</sup> In general, these would operate in distribution in the same way as they currently operate in transmission in Chapter 6A. Associated with this is setting an appropriate threshold; and the AER proposed using the same value as in transmission for capex reopeners and contingent projects, with the AER being able to vary the contingent project threshold values through the use of guidelines.

In respect of cost pass through events, the AER proposed a materiality threshold of one per cent of the ARR to apply to distribution.<sup>387</sup>

The AER also proposed that, where as a result of a cost pass through application the AER allows capex which is fully recovered during the regulatory period in which the relevant event occurs, the capex should not be rolled forward into the RAB at the next regulatory determination.

### **Timeframes for AER decision-making under the uncertainty regime**

When the AER receives an application for cost pass throughs, contingency projects or capex reopeners, it has a set time to make its decision which varies according to the type of application.<sup>388</sup> The AER proposed for it to have more time to consider complex applications, which would involve an aligned timeframe set at 40 business days for normal applications with the ability to extend by an additional 60 business days for more complex or difficult applications.<sup>389</sup>

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<sup>385</sup> MCE SCO, *Response to stakeholder comments on the Exposure Draft of the National Electricity Rules for distribution revenue and pricing*, 1 August 2007, pp. 29, 48.

<sup>386</sup> AER, Rule change request, Part B, 29 September 2011, pp. 46-52.

<sup>387</sup> *Id.*, p. 50.

<sup>388</sup> An exception to this is for negative pass throughs which have no set time limit.

<sup>389</sup> AER, Rule change request, Part B, 29 September 2011, pp. 99-100.

### 11.1.2 Material errors

The NER allow the AER to revoke and substitute regulatory determinations where a material error arises. Depending on whether it is a distribution or transmission regulatory determination, there are different types of material errors which allow for revocation and substitution of regulatory determinations.

The AER was concerned that there may be the potential for a material error that would be outside the currently prescribed list for distribution regulatory determinations.<sup>390</sup> In transmission, uncertainty is created by the power to correct material errors caused by false or misleading information provided by the TNSP as there is no express limit placed on correcting such errors only to the extent necessary.<sup>391</sup> There may also be circumstances in which it may be more preferable or appropriate to amend a regulatory determination, as opposed to revoking and substituting the entire regulatory determination.<sup>392</sup>

The AER sought to remove these differences by broadening its ability to revoke and substitute for material errors in Chapter 6 of the NER. This would entail replacing the prescribed list of material errors in Chapter 6 with a more general reference to material errors or deficiencies, limiting changes related to false and misleading information under Chapter 6A "only to the extent necessary", expanding the circumstances for revoking and substituting regulatory determinations to address deficiencies under Chapter 6A, and being able to amend regulatory determinations in response to material errors.<sup>393</sup>

### 11.1.3 Shared assets

In this final rule determination, shared assets refer to assets used to provide both standard control services or prescribed transmission services and unregulated services. For distribution, the shared asset could be providing a combination of standard control services and unregulated services. For transmission, the shared asset could be providing both prescribed transmission services and unregulated services. This issue is likely to become more relevant in light of the potential for electricity network assets, such as poles and pits, to be used to provide access for the National Broadband Network (NBN).

The AER proposed shared assets cost adjustment mechanisms to allow consumers to benefit where distribution assets are used to provide non-standard control services, including alternative control services and unregulated services.<sup>394</sup> This could include

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<sup>390</sup> Id., pp. 95-96.

<sup>391</sup> Ibid.

<sup>392</sup> Ibid.

<sup>393</sup> False and misleading information is already limited in Chapter 6 in this way. "Deficiency" is already included in Chapter 6. For further information, see AER, Rule change request, Part B, 29 September 2011, p. 96.

<sup>394</sup> AER, Rule change request, Part B, 29 September 2011, p. 60.

an ex ante forecast revenue adjustment to the ARR, or an ex post control mechanism adjustment such as reflecting the portion of revenue from the unregulated service.

#### **11.1.4 Small scale incentive schemes**

The AER proposed that it should have the power to develop incentive schemes outside of those already provided for in the NER.<sup>395</sup> It considered the rule change process for implementing new incentive schemes was cumbersome and over costly. The AER also proposed to amend Chapter 6A of the NER such that it would have discretion to decide whether or not to apply the existing incentive schemes to NSPs at the time of the regulatory determination.<sup>396</sup>

#### **11.1.5 Chapter structure**

The remainder of this chapter is structured as follows:

- section 11.2 summarises the Commission's position in the directions paper and draft rule determination;
- section 11.3 summarises the submissions received in response to the Commission's draft rule determination;
- section 11.4 provides the Commission's analysis of issues in response to submissions received on the draft rule determination; and
- section 11.5 provides guidance on the final rule.

### **11.2 Directions paper and draft rule determination**

#### **11.2.1 Uncertainty regime**

##### **Need for capex reopeners and contingent projects in distribution**

In the directions paper, the Commission decided to include contingent projects and capex reopener mechanisms for distribution. This would better harmonise transmission and distribution, as well as making the NSP more accountable rather than relying on cost pass through applications for uncertain circumstances. A range of reasons were given for why the TNSP and DNSP face similar levels of uncertainty. Unlike competitive businesses, which are better able to adjust their behaviour in response to uncontrollable factors, the TNSP and DNSP are both generally obliged to continue to supply services even where their equipment is exposed to significant risks. In the absence of an uncertainty regime, the added risk for a regulated business would be factored into the cost of capital, forcing it up. A regulated business might also have

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<sup>395</sup> Id., pp. 56-58.

<sup>396</sup> Id., p. 57.

more of an incentive to increase the forecast of capex or opex in its regulatory proposal to factor in circumstances which it cannot predict.

In the draft rule determination, the Commission elaborated further on its position in the directions paper. The Commission's starting point was that Chapters 6 and 6A of the NER should be consistent unless there are substantive reasons for a difference. The Commission accepted that there are certain disadvantages of an expanded uncertainty regime. It could dampen the incentive effects of an ex ante allowance in certain circumstances. It could also create administrative burden for the AER and stakeholders in responding to "mini-determinations" during the regulatory period. On balance, however, the Commission decided to maintain its position from the directions paper.

By setting the thresholds for these mechanisms at the correct level, as further discussed below, only the largest projects or events, which could be expected to have longer lead times, would be captured. Accordingly the administrative burden on stakeholders would be limited. In addition, experience with the uncertainty regime in Chapter 6A indicates that the incentive effects of the ex ante allowance provided under the regulatory determination process would not be substantially weakened.<sup>397</sup>

In respect of whether pass throughs provide sufficient protection, capex reopeners are intended to fulfil a different function by extending protection to very large events which are more difficult to predict and are more difficult to fully provide for as cost pass through events. Contingent projects, on the other hand, apply to a matter which is more specific to a particular business and more likely to occur than a cost pass through.

Stakeholders had previously expressed concerns with expanding the uncertainty regime for distribution. These related to the potential increase in intra-period determinations, administrative burden placed on parties to participate in each application, and weakening the expenditure discipline and price/revenue cap regime.<sup>398</sup> Some suggested that a NSP should be using up its existing expenditure allowance, or reprioritising or substituting its projects, to avoid seeking cost recovery through the uncertainty regime mechanisms.<sup>399</sup> In general, the Commission would expect a NSP to act in this way in respect of smaller projects. The threshold for capex reopeners and contingent projects means that these can only be used for larger projects. For such projects, it will be more difficult for the NSP to accommodate these within the existing allowance.

NSPs also suggested that the current uncertainty regime for transmission is not effective.<sup>400</sup> However, the Commission was of the view that it would be outside the scope of this rule making process to review the effectiveness of the uncertainty regime

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<sup>397</sup> It is noted that under Chapter 6A, these mechanisms have not so far created a significant burden, given that the contingent project mechanism has been used twice while capex reopeners have never been used.

<sup>398</sup> Ethnic Communities' Council of NSW, Directions Paper submission, 16 April 2012, p. 3; EUAA, Directions Paper submission, 16 April 2012, pp. 24, 26.

<sup>399</sup> MEU, Directions Paper submission, 17 April 2012, pp. 47-48, 60.

<sup>400</sup> ENA, Directions Paper submission, 16 April 2012, pp. 27-28, 34-35.

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for transmission. Issues specifically associated with the effectiveness of the cost pass through regime have been addressed as part of another rule change process.

### **Threshold for capex reopener and contingent project applications in distribution**

For contingent projects, the AER proposed a threshold of \$10 million which it considered was consistent with the AEMC's original intention in 2006 to align this with the regulatory test threshold.<sup>401</sup> In the draft rule determination, the Commission noted that there were mixed responses from DNSPs suggesting either the contingent project threshold was too low or too high.<sup>402</sup> The Commission maintained its position from 2006 and considered that the threshold should be aligned to the regulatory test threshold ie the Regulatory Investment Test for Transmission (RIT-T) and the proposed Regulatory Investment Test for Distribution (RIT-D). For this reason, guidelines were considered unnecessary to vary the contingent project threshold or for the contingent project threshold to be indexed by inflation.<sup>403</sup> Instead, the contingent project threshold would be directly linked to the estimated capital cost of the most expensive option to address the identified need under the RIT-T, as varied, for transmission and the proposed RIT-D, as varied, for distribution.<sup>404</sup>

### **Materiality threshold for cost pass through applications in distribution**

The AEMC considered in 2006 the materiality threshold for cost pass through applications in transmission as important to promote stability and predictability of the revenue cap regime for both the regulator and the NSP.<sup>405</sup> Without such a threshold, it was considered that this would lead to greater uncertainty and an increase in administrative costs for the AER to determine a material event.<sup>406</sup> Hence, it was determined that the threshold should be one per cent of the MAR for transmission.

In response to the AER's rule change request, some DNSPs proposed that the materiality threshold for distribution should not be set as a value in the NER.<sup>407</sup> Instead, they considered that it should remain flexible to capture all non-trivial matters and reflect less lumpy capex in distribution.<sup>408</sup> Otherwise, the DNSP would be exposed to unrecoverable risks.<sup>409</sup> However, in the draft rule determination, the Commission was of the view that such an approach would introduce an undesirable

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<sup>401</sup> The regulatory test threshold in transmission has now been superseded by the RIT-T.

<sup>402</sup> Ausgrid, Directions Paper submission, 16 April 2012, p. 7; SP AusNet, Directions Paper submission, 16 April 2012, p. 5.

<sup>403</sup> Victorian DPI, Consultation Paper submission, 8 December 2011, pp. 5, 8.

<sup>404</sup> In distribution, this value is equivalent to the estimated capital cost to the NSP affected by the RIT-D project of the most expensive potential credible option to address the identified need of \$5 million. In transmission, this value is equivalent to the estimated capital cost of the most expensive option to address the identified need which is technically and economically feasible of \$5 million.

<sup>405</sup> AEMC, *Economic Regulation of Transmission Services*, Rule Determination, 16 November 2006, p. 106.

<sup>406</sup> Ibid.

<sup>407</sup> Ausgrid, Consultation Paper submission, 8 December 2011, pp. 30-32.

<sup>408</sup> Ibid.

<sup>409</sup> Ibid.

degree of subjectivity into cost pass through determinations, and give the DNSPs too much of an avenue to submit applications, which may or may not be trivial in nature. On balance, the Commission considered that a materiality threshold needed to be specified to provide for greater certainty to both the regulator and the DNSP.

The Commission understood that the AER applied the one per cent threshold in practice for distribution, even though it is prescribed only for transmission. Therefore, there should not be a significant impact on DNSPs in codifying existing AER practices, and no reason for a difference between transmission and distribution. This would provide for consistency, transparency, predictability and certainty on when the AER would be required to consider cost pass through applications.

### **Double recovery of capex arising from cost pass through applications**

In its rule change request, the AER raised the issue that there would be a potential double recovery of capital costs through both cost pass through applications and including that incurred capex again when establishing the roll-forward RAB for the next regulatory period. In the directions paper and draft rule determination, the Commission supported this proposal to avoid the potential unintended double counting. This would be done by excluding the capital costs recovered through approved cost pass through applications during the current regulatory period from the calculation of the roll-forward RAB for the next regulatory period.

### **Timeframes for AER decision-making under the uncertainty regime**

In the directions paper, the Commission considered extending the timeframe for decision-making on cost pass throughs and capex reopeners, but not in respect of contingent projects. In the draft rule determination, this was extended to contingent projects, given the AER's new evidence of the detail and complexity that may be involved in the AER's assessment of contingent project applications.<sup>410</sup>

In the directions paper, the Commission also considered a number of options relating to the circumstances in which the AER may extend its decision-making time and the extent of time required. In developing a position in the draft rule determination, the Commission considered that sufficient certainty and finality must be taken into account. To a certain extent, the need for fixing the timeframe would promote certainty and finality; however, it would not necessarily allow the NSP the ability to recover efficient costs for unforeseen events if there is a substantial delay that is outside of the NSP's control. For this reason, the Commission supported the AER's suggested principle in the draft rule determination that the "stop the clock" mechanism should apply in those circumstances which are outside of the AER or NSP's control. Such circumstances would be where the AER is waiting on the provision of information by a governmental authority, or is waiting on a judicial body or royal commission to make relevant information publicly available.

With respect to the time taken for the AER to wait on additional information from the NSP, the default decision-making time of 40 business days would be subject to the later

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<sup>410</sup> AER, Directions Paper submission, 2 May 2012, pp. 75-76.

of the date that the AER receives the NSP's information or any additional information associated with the NSP's written application. This requirement for the NSP to provide the AER with additional information the AER requires to make a determination under the uncertainty regime is currently unique for negative cost pass throughs, and extended to positive cost pass throughs, capex reopeners and contingent projects in the draft rule determination. This way, it was unnecessary to apply an extended decision-making timeframe to circumstances where the AER is waiting for additional information from the NSP.

Where the issues being considered are complex or difficult, but the AER has all the information that it needs, then the AER should be able to determine the issues within a set timeframe, albeit perhaps an extended timeframe. The Commission considered that the AER's proposal for an extended timeframe in these circumstances would provide the appropriate balance between giving the AER flexibility and offering some degree of finality and certainty in relation to the making of a decision by the AER. For these purposes, the draft rule adopted similar wording to that in section 107 of the NEL, which described the relevant issues as being of sufficient complexity or difficulty to warrant an extension of time.

In the directions paper, the Commission proposed an option to introduce a notification step where the NSP would be required to notify the AER if it was aware that there may be external events that could have an impact on the application before it makes its application. However, given the flexibility that would be built into the timeframe, such a notification appeared to be unnecessary in the draft rule determination. Nevertheless, the Commission encouraged NSPs to notify the AER in advance of its application if it becomes aware of matters that could potentially delay the AER in making its decision, which would assist in allowing the application to be processed more efficiently.

In the directions paper, the Commission also considered the NSPs' proposal for the AER to issue a draft of its decision where there are complex circumstances.<sup>411</sup> However, to the extent the complex circumstances or any lack of information preclude the AER from forming a view, there did not seem to be any value in requiring the AER to make a draft decision at that stage. The Commission considered that it would be difficult to expect the AER to prepare a draft decision in these circumstances and decided not to prescribe such a requirement. Nevertheless, the AER may also wish to seek to informally consult in the course of considering such matters.

### **11.2.2 Material errors**

#### **Scope for material errors**

In the directions paper, the Commission sought supporting evidence to justify the AER's proposal to broaden the scope for material errors under Chapter 6. There was a lack of evidence noted in the directions paper and draft rule determination to support the view that the AER's current powers constrained its ability to revoke and substitute a regulatory determination for material errors.

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<sup>411</sup> ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp. 196-197.

NSPs also stated that there may have been opportunities for a material error to be corrected in a draft regulatory determination, but the AER has not always utilised its discretion to address the material error.<sup>412</sup> The AER itself observed that the circumstances justifying correction of a material error would be exceptional.<sup>413</sup> On this basis, the Commission decided in the draft rule determination that after the final regulatory determination is made, the regulatory determination should only be able to be changed as a result of merits review outcomes or in very clear and exceptional circumstances. Therefore, the Commission favoured keeping the scope of the material error provisions under Chapter 6 narrow and focussed on "computational" errors by the AER or situations where the AER has received false or misleading information. Provisions such as pass throughs, capex reopeners and contingent projects were considered the appropriate means by which more substantive changes to the regulatory determination should be made.

Expanding on its previous position in 2006, the Commission considered in the draft rule determination that in addition to providing certainty, transparency and maintaining the incentives built into the framework, the finality of the regulatory determinations must be preserved. For finality in a regulatory determination, the AER proposed limiting the timeframe for correcting material errors to six months following the making of the final regulatory determination, which would balance off the AER's proposed expansion of the scope of material errors.<sup>414</sup> Given the Commission's decision to maintain a narrow scope for material errors under Chapter 6, this proposed time limitation for addressing material errors was considered unnecessary.

Consistent with this position, the Commission considered in the draft rule determination that the Chapter 6 provisions provided more certainty and finality in the framework than the equivalent provisions under Chapter 6A, and there should be no reason for differences between Chapters 6A and 6 with respect to these types of material errors as these only relate to computational errors or situations where the NSP has submitted false or misleading information. Therefore, the Commission decided to narrow down the broader Chapter 6A provisions with the narrower Chapter 6 provisions. This also included limiting material errors in regulatory determinations caused by false or misleading information by reference to "to the extent necessary", which is currently the case for distribution regulatory determinations, but not for transmission revenue determinations.

The Commission also noted that an alternative approach to promote certainty and finality in the final regulatory determination could be to not permit it to be revoked and substituted for material errors, as currently has been the approach of the regulator Ofgem in the Great Britain. However, the Commission considered that the limited approach in Australia is appropriate.

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<sup>412</sup> ENA, Directions Paper submission, 16 April 2012, pp. 78-79; Jemena, Directions Paper submission, 16 April 2012, pp. 57-58.

<sup>413</sup> AER, Directions Paper submission, 2 May 2012, p. 74.

<sup>414</sup> Ibid.

## **Amending material errors**

The AER proposed that it should be able to amend, as an alternative to revoking and substituting, a regulatory determination as a result of a material error or deficiency where it is more preferable or appropriate to do so. In the directions paper, the Commission considered that the power to amend regulatory determinations would impact on the NSP's ability to have any such amendments reviewed in a merits review, as noted in some submissions.<sup>415</sup> In the draft rule determination, the Commission maintained its view that the provisions relating to material errors should not be changed to include a power for the AER to amend a determination as a result of a material error.

### **11.2.3 Shared assets**

#### **General position**

In the directions paper and draft rule determination, the Commission considered that customers who pay for one type of regulated service that is provided by a shared asset should not be paying for the full cost of the asset. Instead, those customers should be receiving some benefit from the asset being used for a service other than a regulated service. In the draft rule determination, the Commission elaborated further on the rationale for shared assets.

In the directions paper, the Commission noted that a shared assets cost adjustment mechanism could apply to transmission as well as distribution. In the draft rule determination, the Commission regarded this as consistent with the overall principle of harmonising Chapters 6 and 6A of the NER.

#### **Cost allocation principles**

With respect to a potential overlap between cost allocation principles and shared assets, the Commission noted in the draft rule determination that the cost allocation principles are limited as it would only allocate costs for future assets, as opposed to existing assets. This would create a problem when an asset that was used to provide a regulated service later becomes used to also provide an unregulated service or another regulated service. Under the cost allocation principles, as the costs have already been allocated to this asset, the mechanism cannot accommodate this change in circumstances, unless there has been a reclassification of service.

For these reasons stipulated in the draft rule determination, a shared assets cost adjustment mechanism would be available to the AER to apply to assets that provide both distribution or transmission services and any unregulated service. To avoid any doubt and potential overlap, the Commission stated that the AER's development of any shared assets cost adjustment mechanism must have regard to the cost allocation principles and the NSP's cost allocation method, and any incentives under the NER.

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<sup>415</sup> ENA, Directions Paper submission, 16 April 2012, pp. 78-79; Grid Australia, Directions Paper submission, 16 April 2012, p. 13.

### **Restrictions on the shared assets cost adjustment mechanism**

As discussed in the directions paper, the AER proposed two shared assets cost adjustment mechanisms in the form of an ex ante revenue adjustment and an ex post control mechanism adjustment.<sup>416</sup> It stated that the control mechanism adjustment could be used for sharing a proportion of the pre-tax profits from the unregulated activities with the users of the regulated services.<sup>417</sup>

In the draft rule determination, the Commission did not consider it possible for a shared assets cost adjustment mechanism to share a portion of the profit or revenue from unregulated services. By transferring a portion of this profit or revenue to customers of regulated services, the mechanism would be limiting the revenue that the NSP could earn from the unregulated service. This would have the same effect as regulating the unregulated service, which does not appear to be permitted under the NEL and NER.

### **Shared assets cost adjustment mechanism – cost reduction**

It was decided in the draft rule determination that the shared assets cost adjustment mechanism should operate in a way that would not be based on the profit or revenue received by the NSP from the unregulated service. The best way it was considered that this could work was if the sharing was implemented through a reduction in the costs of the shared asset that are recovered from consumers of the regulated service. That is, instead of recovering 100 per cent of the costs of the shared asset from consumers of the regulated service, a lower proportion would be recovered. A number of principles would be taken into account by the AER in determining this proportion, discussed further below, one of which could be having regard to the manner in which costs have been recovered or revenues reduced by the NSP in the past for a shared asset associated with the unregulated service. However, the shared assets cost adjustment mechanism would not apportion part of the revenue or profit from the unregulated service.

Sharing the benefit resulting from the asset being used to provide an unregulated service, as well as a regulated service, via a reduction in the costs recovered from the consumers of the regulated service, rather than by passing through a portion of the revenue or profits received from the unregulated service, means that there will be a limit on the amount of benefit sharing that is possible. For example, if the costs of the shared assets that are recovered from standard control service customers each year are \$1 million in the absence of any sharing, but revenue from the unregulated use is \$3 million per year, the maximum benefit that could accrue to standard control service customers would be \$1 million per year.

Where the shared assets cost adjustment mechanism takes the form of a reduction in costs apportioned to consumers of the regulated services, a control mechanism adjustment including annual pricing adjustments would not appear to be appropriate.

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<sup>416</sup> AER, Rule change request, Part B, 29 September 2011, p. 60.

<sup>417</sup> *Id.*, p. 61.

A control mechanism adjustment would only be appropriate if the adjustment was linked to an external factor, such as the amount of profit or revenue received under a contract with a third party, and this could be converted into a price or revenue adjustment in the control mechanism in a "mechanistic" way without the AER having to make a subsequent decision. Such an approach would be administratively inefficient, given that the AER would be required to annually make these adjustments, and would create too much uncertainty for the NSP.

Instead of an adjustment to the control mechanism, the reduction in the costs allocated to consumers of the regulated services would feed through the building block determination into the ARR. This reduction would be determined by the AER at a regulatory determination according to guidelines based on the principles set out below. It should reflect the part of the costs of the relevant asset which are being recovered through charging for the provision of the unregulated service. By reducing the ARR for the NSP, the amount recovered from consumers will also be reduced. By including the decision in a regulatory determination, the cost reduction will be fixed for the regulatory period covered by that determination, which provides certainty for the NSP. In addition, this decision would be subject to the scrutiny that comes from consultation as part of the regulatory determination process and any subsequent merits review.

### Timing

In the draft rule determination, the Commission was of the view that the cost reduction would only be implemented at a regulatory determination, regardless of when the sharing arrangement actually commences. This means that the NSP would be required to disclose information on its shared assets as part of its regulatory proposal to the AER. It would be possible for the reduction to occur in respect of a sharing arrangement which had not yet commenced, provided it was known with enough certainty at the time of the regulatory determination. If it was not known with enough certainty then the reduction could not apply until the next regulatory determination, even if the sharing arrangement commenced prior to that determination. There would be no reconciliation or "ex post adjustment" in respect of any sharing arrangement that was put in place during the middle of a regulatory period; the cost reduction would only start from the beginning of the next regulatory period. However, the historical use or revenue of the asset could be used as a factor to forecast future sharing of such an asset. Overall, this should provide the NSP who has a sharing arrangement some certainty as to what cost reduction could be expected. The proposed shared assets cost adjustment mechanism could also take into account Jemena's previous proposal for an exemption period to be given to newly shared assets for a period of several years.<sup>418</sup>

In respect of an ex post adjustment, or "true up", once the actual benefits in a period of a sharing arrangement are known, the Commission considered in the draft rule

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<sup>418</sup> Jemena, Consultation Paper submission, 8 December 2011, p. 107; Jemena, Directions Paper submission, 16 April 2012, pp. 26-27, 31-32.

determination that this should not be necessary.<sup>419</sup> First, if the sharing arrangements are set on the basis of a contract the revenue received should be relatively easy to predict. Second, the revenue received will be only one factor to consider in setting the cost reduction for consumers, which must be based on the cost of assets shared. Third, to the extent revenues received through the sharing arrangements change, the cost reduction can be adjusted at the next regulatory determination for the next regulatory period.

### **Jurisdictional arrangements**

As referred to in the AER's original proposal, the Commission recognised in the draft rule determination that shared assets cost adjustment mechanisms currently exist under jurisdictional arrangements.<sup>420</sup> The approach that has been previously used in Queensland has been grandfathered in NER clause 11.16.3. This grandfathering extends until the next Queensland distribution determination in 2015. Since the mechanism applied is a forecast revenue adjustment made to the building blocks, this could be accommodated under the proposed rules. In South Australia, a profit sharing mechanism has been used, with a portion of the profits from unregulated activities passed onto regulated service users of the shared asset.<sup>421</sup> As described above, such a mechanism would not seem to be permitted under the general NEL and NER provisions.

### **Shared assets providing alternative control services**

As noted in the draft rule determination in respect of distribution, the above approach would only address the situation where one use of the asset is to provide standard control services and another use is to provide an unregulated service. The AER also pointed out that there may be the circumstance where the asset is used to provide both alternative control services and unregulated services.<sup>422</sup> The Commission accepted that alternative control service customers of a shared asset should be paying costs reflective of its use for the provision of alternative control services, and agreed with the AER that there should be no reason why standard control service customers benefit from the use of a shared asset to provide unregulated services, while alternative control service customers do not.

Nevertheless, some submissions on the directions paper stated that the AER's proposal would result in customers of alternative control services being over-compensated through a revenue decrement as well as a separate control mechanism, and that alternative control services should be excluded.<sup>423</sup> The Commission considered in the

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<sup>419</sup> AER, Rule change request, Part B, 29 September 2011, p. 61; Jemena, Directions Paper submission, 16 April 2012, pp. 26-27, 31-32.

<sup>420</sup> AER, Rule change request, Part B, 29 September 2011, p. 59.

<sup>421</sup> Ibid.

<sup>422</sup> AER, Directions Paper submission, 2 May 2012, pp. 34-35.

<sup>423</sup> Ausgrid, Consultation Paper submission, 8 December 2011, p. 33; ETSA, CitiPower and Powercor, Directions Paper submission, 13 April 2012, p. 35; Jemena, Directions Paper submission, 16 April 2012, pp. 26-27, 31-32.



draft rule determination that the AER has considerable discretion in setting the control mechanism for alternative control services under NER clauses 6.2.5(a)-(b) and 6.2.6(b)-(c) and so may impose requirements that only permit the NSP to recover such costs associated with the provision of alternative control services as are appropriately allocated to those services. Therefore, in respect of distribution, the shared assets cost adjustment mechanism would only deal with the circumstance where the asset is used to provide a standard control service.

However, the Commission considered in the draft rule determination that, where one use of the asset is for standard control services and the other use is for alternative control services, the standard cost adjustment described above should still apply for the costs recovered from the standard control service customers.

### **Guidelines and principles**

Bearing in mind the shared assets cost adjustment mechanism described above, the Commission considered in the directions paper and draft rule determination that to facilitate NSPs seeking out and entering into sharing arrangements of the kind discussed here, NSPs would need some certainty about how the AER would determine the cost adjustment appropriate for a particular sharing arrangement.

Part of this certainty would be provided by principles guiding the AER's determination, and which would be set out in the NER. NSPs previously raised a number of principles that could be applied in this regard.<sup>424</sup> In setting these principles, consistent with the NEO, the Commission took the view in the draft rule determination that the approach to a shared assets cost adjustment mechanism should:

- provide clarity and certainty on how the AER would approach sharing the costs;
- provide cost reflective prices to consumers;
- promote innovation in NSP investments; and
- be able to be implemented in practice.

On this basis, the principles listed in the draft rule determination to which the AER must have regard to were:

- the NSP should be encouraged to use assets that provide standard control services for the provision of other kinds of services where that use is efficient and does not materially prejudice the provision of standard control services;

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<sup>424</sup> Ausgrid, Consultation Paper submission, 8 December 2011, p. 33; ENA, Consultation Paper submission, 8 December 2011, pp. 38-39; ENA, Directions Paper submission, 16 April 2012, pp. 36-37; Energex, Directions Paper submission, 16 April 2012, pp. 2-3; Ergon Energy, Consultation Paper submission, 8 December 2011, p. 14; ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp. 23, 97-98; Jemena, Consultation Paper submission, 8 December 2011, pp. 107-109; Jemena, Directions Paper submission, 16 April 2012, pp. 26-27, 31-32.

- a shared assets cost adjustment should not be dependent on the NSP deriving a positive commercial outcome from the use of the asset other than for standard control services;
- a shared assets cost adjustment should be applied where the use of the asset other than for standard control services is material. This means the benefit of sharing the cost of the asset based on use should outweigh the administrative costs of implementing the shared asset cost adjustment mechanism;
- the manner in which costs have been recovered or revenues adjusted in respect of the relevant asset in the past and the reasons for adopting that manner of recovery or adjustment should be taken into account;
- a shared assets cost adjustment should be compatible with the cost allocation principles and cost allocation method; and
- a shared assets cost adjustment should be compatible with incentives that the NSP may have under the NER.

The Commission considered in the draft rule determination that the above principles promoted its objectives on what the shared assets cost adjustment mechanism should achieve.

With respect to determining the appropriate portion of costs for the purposes of a shared assets cost adjustment, the Commission considered in the draft rule determination the most obvious approach is for the AER to base this on the relative use of the asset for the provision of the different kind of services such as the technical use or physical use. Another possible way could include using the ratio between the proportion of revenue from the asset for standard control services and the proportion of revenue from the asset for other than for standard control services over the current regulatory period. However, this should not be taken as precluding the AER from considering other possible bases for sharing the costs of the asset.

The Commission did not accept in the draft rule determination the principle that the NSP should only have to pass on the benefit of a shared asset if it receives a net profit as a result, which was proposed by NSPs to recognise the associated risks of the NSP with sharing arrangements.<sup>425</sup> In general, the NSP should bear the risk so it takes this into account when deciding whether to enter a sharing arrangement, as the Commission considered the NSP to be the party best able to assess and manage this risk.

In addition, for added certainty, the draft rule required the AER to set out in guidelines what its approach would be for determining the appropriate cost reduction for sharing arrangements, having regard to the above principles. Such guidelines may, for example, set out a particular methodology which the AER intends to use.

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<sup>425</sup> Ausgrid, Consultation Paper submission, 8 December 2011, p. 33; ENA, Consultation Paper submission, 8 December 2011, pp. 38-39; Jemena, Directions Paper submission, 16 April 2012, pp. 26-27, 31-32.

In the directions paper, the Commission considered including a draft rule requiring the AER to specify the shared assets cost adjustment mechanism at the framework and approach paper stage. However, the Commission decided in the draft rule determination that this would not be required because the shared assets cost adjustment mechanism would be prescribed in the NER, with supporting guiding principles and guidelines. This meant the NSP would need to submit information on its shared assets to the AER in the regulatory proposal.

#### **11.2.4 Small scale incentive schemes**

In the directions paper the Commission considered that the AER should be allowed to develop small scale pilot or test incentive schemes within an environment that limits the sum of money at risk and the length of time of the scheme. It also proposed that it would be appropriate for the AER to have the discretion to determine whether or not incentive schemes should apply at the time of a regulatory determination in Chapter 6A of the NER, consistent with Chapter 6.

In the draft rule determination, the Commission maintained its position. It elaborated that the AER should have the ability to innovate in this way without having to go through the full rule making process, which may be overly burdensome. It would be good regulatory practice to test or pilot a scheme before full implementation as incentive schemes could otherwise be introduced that lead to unexpected and perhaps unwelcome outcomes as identified by Professor Littlechild.<sup>426</sup> A permanent scheme should, however, be subject to the rule making test given the potential impact of the scheme.

The extent of a small scale incentive scheme should be limited by the sum of money at stake, ie revenue at risk, and the period for which the scheme lasts. In addition the scheme should be subject to consultation with relevant NSPs and other stakeholders before being implemented.

The sum of money at stake should balance the need to be high enough to understand how the scheme would be likely to operate but not so high that there would be a significant impact on a NSP if the scheme did not operate as intended. The Commission considered that this balance would be met if the revenue at stake was one per cent of revenue for a regulatory year if the NSP agrees with this amount, or up to 0.5 per cent of revenue for a regulatory year if the NSP does not. The lower revenue at risk that can be placed on the scheme if the NSP does not agree to it was to reflect that the NSP would have no choice as to whether a scheme is applied to it and the scheme would not have been subject to the rule making process. The AER would also be able to undertake paper trials, ie a scheme in which no money is at risk, as part of its discretion. The limits described above were considered high enough such that the effectiveness of a scheme would be able to be determined.

In terms of a restriction on the period of a scheme, any scheme would last for a maximum of two regulatory periods. If the AER wished the scheme to continue after

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<sup>426</sup> Stephen Littlechild, Advice to the AEMC on Rule Changes, 11 February 2012, p. 19.

this point then it would need to apply for the scheme to be made permanent through the rule change process. This length of time should be long enough for the AER to make a decision on whether the scheme was effective and therefore whether it would be a permanent scheme in the NER.

In addition to these requirements, the Commission did not agree that the draft rule should require the AER to seek the agreement of the NSP before commencing the trial as this would simply give the NSP a right of veto. However, as noted above, the revenue that could be put at risk from the scheme would be lower if the NSP did not agree to the scheme. Restricting the scheme to only parts of a NSP's operations would also overly restrict the AER.

Consistent with the general approach in respect of the rule change, the AER would have to take into account certain factors when developing these schemes. The principles developed for capex sharing schemes were considered broadly appropriate here. These addressed key issues, such as the fact that a scheme should not penalise efficient NSPs. At the same time, the principles were broad so that they did not overly restrict the AER. These factors were also in line with those put forward by the AER for its proposed power to develop other incentive schemes.<sup>427</sup>

The Commission maintained that it would be appropriate to allow the AER to have discretion to determine whether incentive schemes should apply at the time of a regulatory determination in Chapter 6A of the NER, consistent with Chapter 6.

## **11.3 Submissions**

### **11.3.1 Uncertainty regime**

#### **Capex reopeners**

The AER supports the introduction of the capex reopener and contingent projects regime for distribution as it considers this to be an additional option and be low in implementation costs.<sup>428</sup> With respect to capex reopeners, some DNSPs also expressed their support for including this in distribution to deal with unforeseen events which require significant capex for providing reliability and security.<sup>429</sup>

#### **Contingent projects**

On the introduction of contingent projects in distribution, most DNSPs maintain their previous objections to its inclusion.<sup>430</sup> Alternatively, they consider if it is introduced in

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<sup>427</sup> AER, Rule change request, Part B, 29 September 2011, p. 57.

<sup>428</sup> AER, Draft Rule Determination submission, 5 October 2012, p. 14.

<sup>429</sup> SA Power Networks, CitiPower and Powercor, Draft Rule Determination submission, 4 October 2012, pp. 7, 27.

<sup>430</sup> ENA, Draft Rule Determination submission, 4 October 2012, pp. 41-44; SA Power Networks, CitiPower and Powercor, Draft Rule Determination submission, 4 October 2012, pp. 7, 27-29; SP AusNet, Draft Rule Determination submission, 4 October 2012, p. 5.

distribution, then the AER should not be able to "micro-manage" their networks which would mean the AER should not be able to: have regard to whether the proposed expenditure should be included as a contingent project; and propose its own contingent projects by transferring expenditure as a contingent project.<sup>431</sup> Instead, the AER would be applying the capex criteria to determine whether it is satisfied with the forecast or otherwise substitute this with its own.<sup>432</sup>

### **Threshold for contingent projects**

Notwithstanding the DNSPs' opposition to introducing contingent projects in distribution, they consider that if it was to be required, then the threshold should only apply to very large individual projects in the vicinity of \$30 million or five per cent of the ARR.<sup>433</sup> They consider that this value corresponds to projects that are large in size, small in number, based on well-defined trigger events, and proportionate to the size and value of the network.<sup>434</sup> Further, they consider that it should be made clear that the regime only applies to capex for an individual project and not capex related to more than one identifiable project.<sup>435</sup>

On the other hand, the DNSPs do not consider it appropriate to link the distribution contingent project threshold to the RIT-D threshold because of their fundamental difference.<sup>436</sup> The RIT-D threshold assumes it would be desirable in principle for the test to be applied to all projects, but that it should be limited to keep administrative costs proportionate to the benefit.<sup>437</sup> In contrast, the threshold for contingent projects should identify projects that cannot be accommodated in a standard price cap regime with ex-ante forecasts.<sup>438</sup> On the other hand, the NSPs then suggest that linking the characteristics of transmission projects might make it convenient for transmission contingent projects to be linked to the higher threshold of the RIT-T.<sup>439</sup> The joint submission from SA Power Networks, CitiPower and Powercor clarified that they did not support the contingent projects regime, and its reference to a \$5 million threshold in its previous submission was in the context of pointing out an inconsistency between the AER's proposed \$10 million threshold for distribution contingent projects and its link to the RIT-D threshold of \$5 million.<sup>440</sup>

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<sup>431</sup> ENA, Draft Rule Determination submission, 4 October 2012, pp. 41-44.

<sup>432</sup> Ibid.

<sup>433</sup> Ibid.

<sup>434</sup> Ibid.

<sup>435</sup> Ibid.

<sup>436</sup> Ibid.

<sup>437</sup> Ibid.

<sup>438</sup> Ibid.

<sup>439</sup> Ibid.

<sup>440</sup> SA Power Networks, CitiPower and Powercor, Draft Rule Determination submission, 4 October 2012, p. 29.

### Materiality threshold for cost pass through events

With respect to the materiality threshold for cost pass through applications in distribution, some DNSPs maintain that the threshold should be set to \$1 million to provide for certainty, rather than at one per cent of the ARR.<sup>441</sup> However, NSPs consider that if the one per cent threshold were to apply then it should cover an annual culmination of multiple events with the total impact considered as part of the threshold, which would be based on the cash flow impact (ie actual costs incurred) as opposed to the revenue impact.<sup>442</sup> They consider this approach would be consistent with the RPP to allow NSPs a reasonable opportunity to recover at least their efficient costs.<sup>443</sup>

In contrast, the AER has shifted from its original proposal and considers that the materiality threshold may be too low and may capture immaterial applications.<sup>444</sup> It proposes that this threshold should be treated as one factor, but not the only condition to determine the materiality of an application.<sup>445</sup>

#### 11.3.2 Material errors

In the absence of any evidence to demonstrate that the AER has been constrained under the current arrangements for material errors, NSPs do not support changing the current NER provisions under Chapters 6 and 6A, except for making minor amendments to clarify the provisions.<sup>446</sup>

#### 11.3.3 Shared assets

In general, the NSPs and MEU support the shared assets cost adjustment mechanism.<sup>447</sup> However, NSPs consider that further drafting is required to clarify the Commission's intended design.<sup>448</sup> Otherwise, they consider that the Commission's approach to applying a revenue requirement adjustment cannot be achieved with respect to revenue received from shared assets.<sup>449</sup>

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<sup>441</sup> Id., pp. 6-7, 26-27.

<sup>442</sup> Ibid; ENA, Draft Rule Determination submission, 4 October 2012, pp. 44-46; Ergon Energy, Draft Rule Determination submission, 7 October 2012, p. 7.

<sup>443</sup> Ibid.

<sup>444</sup> AER, Draft Rule Determination submission, 5 October 2012, pp. 14-15.

<sup>445</sup> Ibid.

<sup>446</sup> ENA, Draft Rule Determination submission, 4 October 2012, p. 73; Grid Australia, Draft Rule Determination submission, 4 October 2012, pp. 3, 12, 14-15.

<sup>447</sup> ENA, Draft Rule Determination submission, 4 October 2012, pp. 46-49; Energex, Draft Rule Determination submission, 4 October 2012, p. 2; Ergon Energy, Draft Rule Determination submission, 7 October 2012, pp. 7-8; Grid Australia, Draft Rule Determination submission, 4 October 2012, pp. 3, 11-12; MEU, Draft Rule Determination submission, 4 October 2012, p. 28.

<sup>448</sup> Ibid.

<sup>449</sup> Ibid.

NSPs support the approach where revenue is shared between assets with the RAB then allocated according to the types of services used for that asset, as opposed to the capex at the point it enters the RAB.<sup>450</sup> NSPs also support the Commission's approach to allow assets to be shared between standard control or prescribed transmission services with unregulated services.<sup>451</sup> However, they consider that the types of services that could be covered under a shared asset arrangement should be extended so that an asset can be shared between: standard control and alternative control, negotiated and unregulated services in distribution; and prescribed transmission and negotiated or unregulated services in transmission.<sup>452</sup>

To effect the shared assets cost adjustment mechanism, NSPs propose the RAB would include any expenditure for an asset that may be used for standard control or prescribed transmission services.<sup>453</sup> This would result in a "gross figure based" RAB, which can then be subsequently allocated between services that share the asset.<sup>454</sup> This would also require a change to the cost allocation principles so that it refers to the allocation of assets rather than capex.<sup>455</sup>

Associated to this, NSPs consider that past capex that has already been shared should be accounted for under the shared assets cost adjustment mechanism.<sup>456</sup> However, they consider their proposed "gross figure based" RAB would resolve this issue, as opposed to a RAB with only part of the asset value included.<sup>457</sup> This may result in a potential double allocation of costs if the RAB had previously been treated as a "gross figure based" RAB, which can be resolved by specifying that the AER needs to ensure that efficient allocation of costs is made.<sup>458</sup>

NSPs support the first principle which places a positive incentive upon NSPs to identify additional services for assets that provide prescribed transmission or standard control services.<sup>459</sup> However, they do not agree that implementing a shared cost assets arrangement should be contingent on whether there is a positive commercial outcome from such sharing.<sup>460</sup> At a minimum, they consider that the NSP should expect on an ex ante basis to be left whole from allocating the assets, which would be inferred from the first principle and the NEO.<sup>461</sup>

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450 Ibid.

451 Ibid.

452 Ibid.

453 Ibid.

454 Ibid.

455 Ibid.

456 Ibid.

457 Ibid.

458 Ibid.

459 Ibid.

460 Ibid.

461 Ibid.

Grid Australia considers that transmission assets can be solely constructed for providing negotiated or unregulated services, and there is no reason for these particular assets to be shared and included in the RAB.<sup>462</sup> They note that schedule 6A.2 already provides for the situation where that asset later provides prescribed transmission services and is subsequently included in the RAB.<sup>463</sup>

#### **11.3.4 Small scale incentive schemes**

NSPs broadly consider the draft rule determination strikes the right balance between allowing for regulatory innovation and retaining important distinctions between rule making and regulatory application.<sup>464</sup> Other stakeholders did not comment on this aspect of the draft rule determination.

### **11.4 Analysis**

#### **11.4.1 Uncertainty regime**

##### **Contingent projects**

With respect to limiting contingent projects to capex for an individual project and not capex related to more than one identifiable project, the Commission considers it is unnecessary to specify this in the NER.<sup>465</sup> The NER provides that the contingent project needs to be assessed and the associated trigger event defined in the regulatory determination, which determines the scope of the contingent project.

Also, by setting the thresholds for these mechanisms at the correct level, as further discussed below, only the largest projects or events, which could be expected to have longer lead times, would be captured. Accordingly the perceived "micro management" of the process and administrative burden placed on stakeholders would be limited, without the need to consider changing the current design of the uncertainty regime.<sup>466</sup> In addition, experience with the uncertainty regime in Chapter 6A indicates that the incentive effects of the ex ante allowance provided under the regulatory determination process would not be substantially weakened. The Commission notes that under Chapter 6A, these mechanisms have not so far created a significant burden, given that the contingent project mechanism has only been triggered twice while capex reopeners have never been used. However, given the number of contingent projects proposed on an ex ante basis via the regulatory determination process, it may be considered to be currently a significant burden on the AER to assess these.

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<sup>462</sup> Grid Australia, Draft Rule Determination submission, 4 October 2012, pp. 11-12.

<sup>463</sup> Ibid.

<sup>464</sup> ENA, Draft Rule Determination submission, 4 October 2012, p. 36.

<sup>465</sup> Id., pp. 41-44.

<sup>466</sup> Ibid.



### Threshold for contingent projects

In considering the ENA's reasons for the inappropriateness of basing the distribution contingent project threshold on the RIT-D and proposing an alternative threshold of \$30 million or five per cent of the ARR (whichever is greater), the Commission has reconsidered its past position.<sup>467</sup>

In 2006, the AEMC considered that the relationship between the contingent project threshold for transmission and the regulatory test threshold had the advantage that it would be the same amount necessary for the application of the regulatory test to new augmentation investment.<sup>468</sup> Part of this was also based on information supplied by the Electricity Transmission Network Owners Forum (ETNOF) (now Grid Australia) and considering a number of indicative costs for potential contingent projects.<sup>469</sup>

In the draft rule determination, the Commission noted that the regulatory test threshold referred to in the 2006 determination had been replaced with the RIT-T, but the contingent project threshold had not been adjusted in the NER to reflect this change. On this basis, the Commission considered that the threshold should have been lowered to \$5 million to reflect its original intention ie from \$10 million to \$5 million. Conveniently, this contingent project threshold for transmission would have then been the same as in the proposed approach for distribution as they would be both linked to their respective RIT-T and RIT-D thresholds which have the same monetary value.

On the NSPs' point that the distribution contingent project should be set at a level equivalent to the characteristics of transmission contingent projects, the Commission does not accept that the monetary threshold should be different.<sup>470</sup> This would imply that projects in distribution are generally larger than those in transmission, which is questionable. Instead, the thresholds should be at the same level. On this basis, to determine an appropriate threshold, the anticipated value of projects accepted by the AER in recent transmission regulatory determinations was examined. These are shown in Appendix B.

As can be seen in Appendix B, for ElectraNet and Transend, half of their current contingent projects would have not fallen under the NSPs' proposed \$30 million contingent project threshold. However, Powerlink and TransGrid would not have been affected. In addition, if the threshold is the greater of \$30 million and five per cent of the ARR or MAR, increasing one boundary of the threshold to \$30 million will mean for some NSPs that this value will become greater than their five per cent of the ARR or MAR, and therefore their threshold will be based on a higher value of \$30 million. This demonstrates that under the NSPs' proposal, the number of contingent projects to be proposed, assessed and defined, and volume of applications submitted to the AER (if they had been triggered) would be reduced. Further, the fact that only two contingent projects have been triggered to date (noting the Powerlink regulatory period has only

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<sup>467</sup> Ibid.

<sup>468</sup> AEMC, *Economic Regulation of Transmission Services*, Rule Determination, 16 November 2006, p. 59.

<sup>469</sup> Id., pp. 58-59.

<sup>470</sup> ENA, Draft Rule Determination submission, 4 October 2012, pp. 41-44.

commenced mid 2012) may suggest that very uncertain projects are being proposed as contingent projects. Therefore, the administrative burden placed on the AER to consider a number of contingent projects during the regulatory determination process would be reduced by applying a higher monetary threshold for contingent projects. This issue becomes more evident if the AER considers multiple applications from different NSPs concurrently.

NSPs have suggested that the reason for the small number of triggered contingent projects is because the AER has taken a narrow interpretation of the trigger event and not defined it properly.<sup>471</sup> In the end, this is a matter for the AER.

For the above reasons, the Commission has decided that the contingent project threshold will be the greater of \$30 million or five per of the ARR or MAR for both distribution and transmission. Future projects with a monetary value of between \$10 million and \$30 million will have to be assessed by the AER as part of the revenue allowance under the regulatory determination. This means that there is an appropriate balance between providing sufficient scrutiny of adequately large projects under the contingent project regime and other projects under the regulatory determination, and a reduction in the administrative burden placed on the AER and NSPs.

In fixing the threshold to the greater of \$30 million or five per of the ARR or MAR, guidelines for varying the threshold and indexation of the threshold may be relevant considerations.<sup>472</sup> However, for reasons of certainty and administrative simplicity in applying the threshold, these options have not been pursued further. Further, changing the threshold value from the current arrangements can be considered as only a minimal change to design of the contingent projects regime as opposed to introducing indexation or a new guideline process.

### **Materiality threshold for cost pass through events**

The Commission does not accept the NSPs' proposal for an annual accumulation of multiple cost pass through events to be considered when assessing the materiality of the cost pass through event application, nor setting the threshold to \$1 million.<sup>473</sup> The Commission does not accept the AER's proposal to make it only one factor for consideration in assessing materiality.<sup>474</sup> On the one hand, the AER considers the threshold may be too low; while on the other, the NSPs consider it too high. This highlights the problem with not setting the materiality threshold as it creates divided views on its objective. As the AEMC stated in 2006, setting the materiality threshold to one per cent of the MAR is important to promote stability and predictability of the regime for both the regulator and the NSP.<sup>475</sup> In the absence of a specified materiality

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<sup>471</sup> Ibid.

<sup>472</sup> Victorian DPI, Consultation Paper submission, 8 December 2011, pp. 30-32.

<sup>473</sup> SA Power Networks, CitiPower and Powercor, Draft Rule Determination submission, 4 October 2012, pp. 6-7, 26-27; ENA, Draft Rule Determination submission, 4 October 2012, pp. 44-46; Ergon Energy, Draft Rule Determination submission, 7 October 2012, p. 7.

<sup>474</sup> AER, Draft Rule Determination submission, 5 October 2012, pp. 14-15.

<sup>475</sup> AEMC, *Economic Regulation of Transmission Services*, Rule Determination, 16 November 2006, p. 106.

threshold, it would lead to greater uncertainty and an increase in administrative costs for the AER to determine a material event.<sup>476</sup>

Proceeding on the basis that the materiality threshold is set at one per cent of the ARR or MAR, the NSPs' proposed accumulation of multiple cost pass through events for a given year cannot be accepted. Firstly, the NSPs' proposal would dilute the effect of the materiality threshold. Secondly, the experience in transmission demonstrates that a non-cumulative materiality threshold can be applied without any problems. Finally, the approach reflects the AER's current practice in applying the materiality threshold for cost pass through applications.

In terms of whether the costs associated with the materiality threshold are based on cash flow impact or revenue impact, that is a matter of detail for the AER to decide with respect to each particular application.<sup>477</sup> The Commission considers that it is sufficient to refer to the ARR as defined in the NER, without further elaborating on its existing definition.

For the above reasons, the materiality threshold for cost pass through events will be set at one per cent of the ARR for distribution.

#### **11.4.2 Material errors**

While the material error provisions have not been used extensively, the Commission considers that the provisions under Chapter 6 provide for more certainty and finality in the framework than the equivalent provisions under Chapter 6A. Further, there should be no reason for differences between Chapters 6A and 6 with respect to these types of material errors as these only relate to computational errors or situations where false or misleading information has been submitted. Therefore, the broader Chapter 6A provisions should be narrowed down to be consistent with the Chapter 6 provisions. This also includes limiting material errors in regulatory determinations caused by false or misleading information by reference to "to the extent necessary", which is currently the case for distribution regulatory determinations, but not for transmission revenue determinations.

#### **11.4.3 Shared assets**

##### **Services covered under the shared asset cost adjustment mechanism**

In designing the shared asset cost adjustment mechanism, the Commission intends that costs that customers incur for a service should be cost reflective. The shared assets cost adjustment mechanism allows users of an asset to benefit where the asset is used for a different service.

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<sup>476</sup> Ibid.

<sup>477</sup> SA Power Networks, CitiPower and Powercor, Draft Rule Determination submission, 4 October 2012, pp. 6-7, 26-27; ENA, Draft Rule Determination submission, 4 October 2012, pp. 44-46; Ergon Energy, Draft Rule Determination submission, 7 October 2012, p. 7.

In the draft rule determination, reference was made to the shared asset cost adjustment mechanism applying where the other use of the asset is an alternative control service.<sup>478</sup> In fact, the nature of the other types of regulated services (including alternative control services and negotiated services) means that the possibility of sharing is less likely. If, for example, a standard control service asset is used for alternative control service purposes, it is more likely that the service as a whole would be reclassified, making a sharing arrangement unnecessary. For simplicity, it is preferable to restrict the shared assets cost adjustment mechanism to arrangements where one use of an asset is for a standard control service or prescribed transmission service and the other use is for an unregulated service. Also, this would reduce the possibility of an overlap between the shared assets cost adjustment mechanism and the cost allocation principles which would have resulted in a double recovery.

Some submissions in response to the draft rule determination sought the inclusion of negotiated services within the shared assets cost adjustment mechanism. Given the flexibility in the way costs for negotiated services are recovered, the Commission does not see it as necessary for the shared assets cost adjustment mechanism to extend to negotiated services. A similar comment was made in respect of alternative control services in the draft rule determination.<sup>479</sup>

### **Gross figure based RAB**

The Commission has not altered the current way in which capex is allocated to the RAB based on only standard control services. To change it to become a "gross figure based" RAB as proposed by the NSPs would result in a significant change in the existing way in which cost allocation and ring fencing guidelines operate. To effect such a change would create too much uncertainty as to the setting of the RAB and result in a volatile RAB for each regulatory reset.

The purpose of the shared assets cost adjustment mechanism is to address the situation where an asset used for a standard control service or prescribed transmission service is subsequently shared with an unregulated service, and the AER then could apply a revenue adjustment without resorting to reallocating the initial RAB value. If at the point where the capex enters the RAB it has been recognised that the asset is being used for unregulated services, and only the standard control services portion is included in the RAB, then the shared assets cost adjustment mechanism should not need to apply. This is because the mechanism is based on the presumption that the asset has not been shared at that stage. This should clarify the treatment of past assets where part of the past capex has already been allocated to other unregulated services. In that scenario, the shared assets cost adjustment mechanism would not be needed. To reinforce this point, a principle has been included which requires the AER to have regard to the manner in which costs have been recovered or revenues reduced with respect to the asset in the past.

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<sup>478</sup> AEMC, *Consolidated Rule Request – Economic Regulation of Network Service Providers*, Draft Rule Determination, 23 August 2012, p. 212.

<sup>479</sup> *Id.*, p. 211.

## **Positive commercial outcome**

The Commission reiterates its position that, in general, the NSP should have to bear some risk in the sharing arrangements so it takes that risk into account when deciding whether to enter a sharing arrangement of an asset. The NSP will be in the best position to assess and manage this risk. The NSP needs to be prudent in making its investment decisions when going into sharing arrangements. A benefit that the NSP may receive in sharing the asset is the likely potential to substantially gain revenue from that arrangement; while the only benefit to the existing customer is a reduction in its costs. It is the NSP's decision to share the asset with the objective of making a profit, balanced against whether it is a prudent decision to enter into such an arrangement. Otherwise, there would be no disincentive for the NSP to share an asset irrespective of the risk as it would pass on the costs to customers if it makes a bad investment decision.

### **11.4.4 Small scale incentive schemes**

The Commission notes that the majority of the issues raised by NSPs on small scale incentive schemes were also raised in relation to capex sharing schemes. In particular NSPs suggested that:

- the AER should be required to compensate NSPs for the expected liability under the scheme where a scheme is asymmetric; and
- NSPs should have certainty on applicable schemes at the framework and approach stage.<sup>480</sup>

These issues are considered in sections 9.4.1 and 9.4.2.

The Commission does not agree with SP AusNet that the AER and NSPs should be allowed to agree on a revenue at risk higher than currently provided for. Given that the schemes will not have been subject to the rule-making test, the revenue at risk is appropriate. This will provide protection to both consumers and NSPs.

## **11.5 Guidance on final rule**

### **11.5.1 Uncertainty regime**

#### **Capex reopener and contingent projects in distribution**

Generally, the uncertainty regime has been aligned in distribution with transmission. This means that the capex reopener, contingent project and cost pass through arrangements are broadly the same.

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<sup>480</sup> ENA, Draft Rule Determination submission, 4 October 2012, pp. 36-38.

### **Threshold for capex reopener and contingent project applications in distribution**

For capex reopeners, the threshold for distribution is capex that exceeds five per cent of the value of the roll-forward RAB for the first year of the regulatory period. The same threshold applies to both transmission and distribution.

For contingent projects, the threshold for both distribution and transmission is the greater of \$30 million or five per cent of the ARR or MAR, respectively. The same threshold applies to both transmission and distribution.

### **Materiality threshold for cost pass through applications in distribution**

The materiality threshold for cost pass through applications in distribution is one per cent of the DNSP's ARR. This brings it into line with the threshold applied in transmission.

### **Other aspects of cost pass through applications**

Under the existing rules, the roll-forward RAB for the next regulatory period must include all capital costs incurred in the current regulatory period. This may unintentionally include pass through amounts associated with capital costs which have already been approved under the cost pass through arrangements. For clarity, the final rule amends the NER to reflect the fact that cost pass through amounts that have already been recovered in a regulatory period cannot be recovered again in the roll-forward of the RAB for the next regulatory period.

For the reasons explained above, the timeframes for the AER to make a decision on applications related to cost pass throughs, contingent projects and capex reopeners have been aligned at 40 business days from the time the AER receives the application and any additional information it requires from the NSP. This timeframe will be able to be extended by up to a further 60 business days if the AER determines that there are issues of sufficient complexity or difficulty that warrant such an extension. Such issues may require the AER to seek expert advice or consult with interested parties on a particular matter.

If the decision needs to be delayed to wait for further information from a third party, then a "stop the clock mechanism" will be able to apply. Such a third party may be a governmental authority from which the AER has requested information or a judicial body or a royal commission that the AER anticipates will make publicly available information that is relevant to the NSP's application.

In the case of either a time limit extension or the application of the "stop the clock" mechanism, the AER will be required to notify the NSP of the extension or delay no later than 10 business days before the date that the AER would have to make its decision (ie no later than 30 business days from the time the AER receives the application) and also publish notice of this on its website. In addition, the AER may also apply the "stop the clock" mechanism after it had already extended the period, but the AER would still be required to notify the NSP no later than 10 business days before the expiration of the extended date (ie no later than 90 business days from the time the

AER receives the application). The AER will also be required to advise the NSP when the "stop the clock" mechanism has ceased to apply, in which case it must again publish a notice on its website to this effect.

**Case scenario – example of the "stop the clock" mechanism and extending timeframe by 60 business days**

- On 1 July 2013, the AER receives from a NSP in New South Wales an application for a positive cost pass through within 90 business days of the positive event occurring. The application relates to a bushfire.
- At the time of the application, the AER is informed by the NSP that there is a royal commission on the bushfire and the outcome of the decision by the royal commission may have an impact on whether the NSP can recover for that cost pass through and, if allowed, potentially also the amount that the NSP can recover. The royal commission decision will not occur until after the normal decision-making timeframe for the AER, ie more than 40 business days after the AER received the NSP's application and such additional information regarding the application as the AER requires from the NSP.
- On 15 July 2013, the AER notifies the NSP that in order to determine the NSP's application, it requires information that it anticipates will be made publicly available by the royal commission. This notification occurs no later than 10 business days before it would have had to make the decision. The AER also publishes a notice on its website stating that the clock has stopped.
- On 29 November 2013, the royal commission publishes its decision. As a result of this, the "stop the clock" mechanism ceases to apply. The AER would inform the NSP and publish a notice on its website stating that the clock has restarted. The Commission would also expect the AER to state in that notice the date on which the AER will make its decision. In this case, it will be 30 business days after 29 November 2013, which will be 15 January 2014, taking into account public holidays. This is because 10 business days have already elapsed between 15 July 2013 and the time the clock stopped.
- However if, upon reviewing the royal commission decision, the AER determines that it requires more time to address a complex question related to the application, the AER could extend the decision-making period by a maximum period of a further 60 business days. To do so, the AER would need to notify the NSP of its decision to extend by no later than 10 business days before it would otherwise have had to make its decision on 15 January 2014. Therefore, the AER would need to give its notice, with respect to extending the period by the maximum of 60 business days, no later than 31 December 2012. The AER would also need to publish notice of the extension on its website as soon as reasonably practicable. The maximum additional period for the AER to make its decision will then expire on 10

April 2014.

- Note: In the scenario above, the "stop the clock" mechanism could only be triggered by the royal commission. The "stop the clock" mechanism does not apply to considering complex or difficult questions on the matter, where the timeframe can only be extended by a maximum additional period of 60 business days.

Given the introduction of capex reopeners and contingent projects for distribution, the timeframes for the AER to decide on these applications have been aligned with those in transmission.

Another consequential change relates to the decision making timeframe for negative cost pass through applications. The Commission notes that there is currently no set decision-making timeframe for this type of application, although a timeframe exists on when the application needs to be made. Previously in the Chapter 6A rule determination, the AEMC noted that there are asymmetries between positive and negative pass through applications that justify a difference in their treatment. However, with respect to decision-making timeframes, there should be no difference as the AEMC in 2006 recognised for capex reopeners and contingent projects. The decision-making timeframe for negative pass through applications has therefore been aligned so that there is a "standard" 40 business day timeframe with an option to extend as with the other types of applications. In addition, the AER will expressly be required to notify all NSPs of the occurrence of a negative change event if that event is not notified by the NSP to the AER and the AER proposes to determine a pass through amount.

However, unlike for positive change events, if the AER fails to make a pass through determination in respect of a negative change event within the 40 business day time limit, then the AER will be taken to have determined a zero pass through amount, noting that this 40 business day period can still be extended to accommodate issues that are difficult, and that the "stop the clock" mechanism will still apply where the AER is waiting on information from a governmental authority, judicial body or royal commission. As noted above, the reason for the different treatment of a default decision for negative cost pass throughs compared to positive cost pass throughs is due to the asymmetries between positive and negative pass through applications.

### 11.5.2 Material errors

Aligning the Chapter 6A provisions with the Chapter 6 provisions with respect material errors means that the AER will now only be able to revoke and substitute a transmission revenue determination or amend a pricing methodology for the following kinds of material errors or deficiencies:

- a clerical mistake or an accidental slip or omission;
- a miscalculation or misdescription;



- a defect in form; or
- a deficiency resulting from the provision of false or materially misleading information to the AER.

As with Chapter 6, for Chapter 6A the substituted revenue determination or amended pricing methodology will only be able to be varied from the revoked revenue determination or existing pricing methodology to the extent necessary to correct the relevant material error or deficiency.

### 11.5.3 Shared assets

The following case study is provided in this section to explain how the shared assets cost adjustment mechanism could work.

#### Case scenario

- In year 2 of a regulatory period the NSP enters into a commercial agreement with NBN Co to allow NBN Co to use electricity poles currently used for standard control service purposes. The rate is \$2,000 per pole per year. The NSP's costs are \$500 per pole per year.
- Given that this occurs during a regulatory period, no shared assets cost adjustment mechanism is applied until the next regulatory determination.
- In its regulatory proposal for the next regulatory determination, the NSP provides details of the shared assets in accordance the AER's regulatory information instrument.
- During the regulatory determination process, the AER decides whether to apply the shared assets cost adjustment mechanism in respect of the NBN arrangements for the next regulatory period. In making this decision, the AER takes into account the guidelines on how to apply the shared assets cost adjustment mechanism and the principles on whether a shared assets cost adjustment mechanism should apply. Some considerations at this point could include the materiality of the shared asset.
- Next, the AER would need to decide on the reduction in the costs for the assets that should not be recovered from standard control customers based on the guidelines. However, it would not directly pass through any of the profits or revenue gained by the NSP as a result of providing NBN Co access to its asset. A possibility could be to base this decision on the number of customers who will benefit from the electricity poles being used to provide NBN services compared to the number of customers who receive standard control services through the use of those electricity poles. For the purposes of this exercise, it may be too difficult to determine the number of customers, but it may be easier to determine that there is an equal share in the technical and/or physical use of that pole for standard

control services and NBN services. It may decide the cost reduction should be on a pole by pole basis over the forthcoming regulatory period.

- Once the AER determines the appropriate reduction of costs for standard control service customers, the AER needs to incorporate this into its building block determination. This determination leads to adjustments being made to the ARR and therefore being reflected in pricing to customers in the annual pricing approval process. In this case, based on the asset being shared according to physical and/or technical use, which has been attributed at 50 per cent, the reduction in the ARR is \$250 per pole per year. This reduction only starts to apply from the following regulatory period and there would be no cost reduction for the period in which the commercial agreement was first put in place.

#### **11.5.4 Small scale incentive schemes**

The final rule gives the AER a broad discretion as to the schemes it may design. The schemes are intended to provide for incentives not already covered by the existing incentive schemes in the NER and may cover matters not related to expenditure by NSPs. For example, the AER could design a scheme which provides rewards for NSPs which engage more effectively with consumers. The final rule provides broad discretion so that the AER can develop any type of scheme that contributes to the NEO.

The principles are consistent with those for capex sharing schemes and therefore the guidance for these principles in section 9.5.2 is also appropriate here. Similarly, as with capex sharing schemes the AER is to set out its likely approach to the application of a scheme to a particular NSP in the framework and approach paper for the NSP. The NSP can then set out in its regulatory proposal how it proposes the scheme should apply, including any proposed values. The AER is to then set out how the scheme will apply to the NSP in the draft and final regulatory determination for the NSP.

## 12 Electricity transitional arrangements

### Summary

- This final rule determination provides for a number of significant changes to Chapters 6 and 6A of the NER and also requires the AER to develop a number of guidelines by 29 November 2013. At the same time that the AER is to develop the guidelines, seven NSPs are due to start their regulatory determination processes and another eight are due to commence theirs within 12 months of the last date by which the guidelines are to be finalised. Transitional rules are therefore required to:
  - enable the new rules and guidelines to be applied in the next round of determinations; and
  - minimise the resourcing burden that the guidelines development processes and transitional arrangements could otherwise place on stakeholders, whilst also allowing consultation with stakeholders.
- Having considered a range of options, the Commission has decided to:
  - exclude those NSPs that are due to commence their regulatory periods post 2016 from the transitional arrangements (Aurora, Powerlink, ElectraNet and Murraylink); and
  - apply different transitional arrangements to the remaining NSPs.
- The transitional arrangements to be applied to the remaining group of NSPs will result in all decisions made by the AER from May 2014 onward being carried out in accordance with the new Chapters 6 and 6A rules and guidelines. An overview of these arrangements is provided below.
- SP AusNet (transmission), which is due to commence its next regulatory period on 1 April 2014, will be subject to the old Chapter 6A rules for three years before moving to the new rules on 1 April 2017.
- ActewAGL, Ausgrid, Endeavour Energy, Essential Energy, TransGrid and Transend are all due to commence their next regulatory period on 1 July 2014. This group of NSPs will have their full determination processes delayed by 12 months and will be subject to the placeholder with true-up model. In short, this model requires the AER to:
  - conduct a high level review of a NSP's placeholder revenue requirement and make a determination before the transitional year;
  - make a full determination during the transitional year for years 2-5 and the transitional year, in accordance with the new Chapter 6 and 6A rules; and
  - use a net present value (NPV) neutral true-up mechanism to account for any difference between the placeholder value and the transitional year revenue requirement established in the full determination.

- Directlink, which is due to commence its next regulatory period on 1 July 2014, will not have its determination process delayed but it will be subject to an 11 month determination process rather than the 15 month extended process.
- Energex, Ergon, SA Power Networks are due to commence their next regulatory period on 1 July 2015 while CitiPower, Jemena, Powercor, SP AusNet and United Energy are due to commence theirs on 1 January 2016. This group of DNSPs will have their determination processes delayed by five months and will be subject to the preliminary determination with mandatory re-opener model. At its most elementary, this model involves:
  - using the AER's draft determination as a placeholder for a NSP's revenue requirement and prices until the final determination is made; and
  - using an adjustment mechanism to account for any difference between the draft and final determinations in NPV neutral terms.

From a legal perspective, a binding determination must be in place before the regulatory period commences. The draft determination is therefore referred to as a preliminary determination while the final determination, which revokes and replaces the preliminary determination, is referred to as the substitute determination. Although the terminology differs, the decision making and consultation process that occurs between the preliminary and substitute determinations are intended to be the same as what would occur between a draft and final determination.

- These transitional arrangements may be viewed as a continuum, with the time taken to transition to the new rules and the differences between the standard determination process and the transitional determination process diminishing over time.

## 12.1 Introduction

This final rule determination provides for a number of significant changes to be made to the rate of return, capex, opex, incentive scheme and regulatory process provisions in Chapters 6 and 6A of the NER. It also requires the AER to develop a number of guidelines by 29 November 2013, including:

- rate of return guidelines;
- capital expenditure incentive guidelines;
- expenditure forecast assessment guidelines;
- shared asset guidelines; and
- confidentiality guidelines.

These guidelines are intended to play an integral role under the new rules and the NSPs, the AER and the appeal body are expected to have significant regard to them as the starting point for each regulatory determination.

Over the same period that the AER is required to develop these guidelines, seven NSPs<sup>481</sup> are due to submit their regulatory proposals. Another eight NSPs<sup>482</sup> are due to submit their proposals within 12 months of the date by which the NER requires the guidelines to be finalised. Given the degree of overlap between the guideline development and regulatory determination processes, the Commission has given further consideration to the transitional arrangements that could be put in place to:

- enable the new rules and guidelines to be applied to NSPs in the next round of regulatory determinations;
- provide NSPs sufficient opportunity to take account of the new guidelines when preparing their regulatory proposals and allow sufficient time for stakeholder consultation;
- provide those NSPs that are subject to any transitional arrangements with a reasonable opportunity to recover at least their efficient costs; and
- minimise the resourcing burden that the guideline development and regulatory determination processes could otherwise place on the AER, NSPs and other stakeholders.

The remainder of this chapter is structured as follows:

- section 12.2 sets out the principles that the Commission considers should guide the development of transitional arrangements;
- section 12.3 provides an overview of the consultation process and the alternative transitional arrangements that were canvassed during this process;
- section 12.4 contains a summary of the submissions received;
- section 12.5 outlines how the first set of guidelines are to be developed;
- section 12.6 examines the need for transitional arrangements;
- section 12.7 identifies the NSPs that will be subject to the transitional arrangements and the period over which the transitional rules will operate;
- section 12.8 sets out the Commission's final decision on the form that these arrangements should take;

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<sup>481</sup> The seven NSPs are: SP AusNet (transmission), TransGrid, Transend, ActewAGL, Endeavour Energy, Essential Energy and Ausgrid

<sup>482</sup> The eight NSPs are: Ergon, Energex, SA Power, Jemena, United Energy, CitiPower, Powercor and SP AusNet (distribution).

- sections 12.9 to 12.12 provide further guidance on how the transitional rules are intended to be applied to those NSPs that will be subject to the arrangements; and
- section 12.13 contains a summary of the transitional arrangements that will apply to each NSP and the timetable for the next round of regulatory determinations.

## 12.2 Principles guiding the development of transitional arrangements

In its consultation paper, the Commission set out four principles that, in its view, represented the most important considerations in developing transitional arrangements. These principles are:

1. the final rules when made in November 2012 should apply to all service providers as soon as possible. This includes those service providers currently due to submit regulatory proposals in February and May 2013;
2. where any transitional arrangements are made regarding determination processes that require consultation, the arrangements should allow sufficient time for stakeholder consultation;
3. the transitional arrangements should provide service providers with a reasonable opportunity to recover at least the efficient costs they incur in the provision of regulated services; and
4. any transitional arrangements should be practicable having regard to the regulator's resourcing constraints, as well as the resourcing capacity of other stakeholders.

During the consultation process it became apparent that there was a fifth principle that the Commission should have regard to when developing transitional arrangements.<sup>483</sup> That is, any arrangements put in place to facilitate the transition to the new rules should minimise the potential for one-off price shocks.

For the reasons set out in sections 2.4-2.6, the Commission is of the opinion that these five principles are consistent with both the NEO and the RPP. The Commission has therefore borne these principles in mind when assessing the various proposals that have been made about the form that the electricity transitional arrangements should take.

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<sup>483</sup> During the consultation process, some stakeholders noted that if there was a one year determination followed by a full four or five year determination, there could be a significant change in prices between the transitional and full determinations because the AER would not be able to smooth price changes over the two determinations. This form of price volatility would be contrary to the long term interests of consumers, so the Commission has been cognisant of the desirability for the transitional rules not to give rise to one-off price shocks.

### 12.3 Consultation process and alternative models canvassed

On 14 September 2012, the AEMC published a consultation paper on the arrangements that could be applied to both gas and electricity service providers to facilitate the transition to the new rules. As part of this consultation paper, the Commission outlined the arrangements that could be put in place to:

- enable NSPs to transition to the new rules and guidelines in the next round of regulatory determinations; and
- minimise the resourcing burden that the guidelines development processes and the transitional arrangements could otherwise place on the AER, NSPs and other stakeholders.

In short, the proposal set out in the consultation paper provided for a 12 month delay to the commencement of the next full regulatory period for all NSPs except ElectraNet, Murraylink and Directlink. It also provided for the following determination processes:

- a limited scope determination process, which was to be carried out for the 12 month transitional period using a mixture of old and new rules; and
- a normal determination process, which was to be carried out for the delayed full regulatory period in accordance with the majority of the new rules and guidelines.

Within the consultation paper, the Commission encouraged stakeholders to suggest alternative approaches if they considered there were better arrangements to those outlined above.

To facilitate further discussion on this issue, the AEMC held a stakeholder workshop on 26 September 2012. During the workshop it became apparent that the AER and NSPs had a number of concerns with the arrangements proposed in the consultation paper. These concerns primarily related to:

- the potential for a one year limited scope determination to result in one-off price and revenue shocks; and
- the complexities, resource intensity and other inefficiencies associated with carrying out two full determination processes within two years.

A week and a half after the stakeholder workshop, TransGrid provided a submission to the AEMC, which set out an alternative model for the transitional arrangements.<sup>484</sup> In simple terms, the TransGrid model provides for a 12 month delay to the full determination process whilst also maintaining the current schedule of regulatory periods. It does so by allowing:

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<sup>484</sup> TransGrid, Consultation Paper on Savings and Transitional Arrangements submission, 8 October 2012.

- a placeholder value to be used for a NSP's revenue requirement in year 1, which is established through a high level regulatory review process conducted by the AER shortly before the commencement of that year;
- a full determination of the NSP's revenue requirements for years 1-5 to be carried out by the AER, in accordance with the new rules and guidelines, 12 months later than it would otherwise be required to do so; and
- any difference between the placeholder value and the year 1 revenue requirement established through the full determination process to be accounted for by the use of a net present value (NPV) neutral true-up mechanism.

TransGrid's proposal prompted further consultation between the AEMC, the AER, NSPs and consumer groups. It also resulted in the identification, including by the AEMC, of a number of other variants of the TransGrid placeholder with true-up model, including the mechanistic<sup>485</sup> and hybrid<sup>486</sup> placeholder models.

Another model that was identified by the AEMC during the consultation process was the preliminary determination with mandatory re-opener model. At its most elementary, this model involves:

- using the AER's draft determination as a placeholder for a NSP's revenue requirement and prices until the final determination is made; and
- using an adjustment mechanism to account for any difference between the draft and final determinations.

This model is referred to as the "preliminary determination with mandatory re-opener model" because, from a legal perspective, a binding (final) determination must be in place prior to the start of a regulatory period. The application of this model therefore requires:

- a final determination to be made in advance of the regulatory control period. In effect, what would have been the draft determination under a full determination process becomes the final determination. Because of its subsequent re-opening, this determination is referred to in the remainder of this chapter as the "preliminary determination"; and
- a mandatory re-opening of the preliminary determination and the substitution of this determination with a new determination by the AER. The new determination is, in effect, the final determination that would have arisen through the usual

<sup>485</sup> The mechanistic model works in precisely the same way as the TransGrid model but rather than the AER reviewing the placeholder revenue, the transitional rules would require a NSP's placeholder revenue to fall below a cap specified in the rules.

<sup>486</sup> This model, as its name suggests, is a hybrid of the mechanistic and TransGrid models. Under this model, a NSP's placeholder revenue could be either: below a cap specified in the transitional rules, in which case the proposed placeholder revenue is automatically accepted; or above a cap specified in the transitional rules, in which case the AER is required to conduct a high level assessment of the proposal.



determination process. This new determination is referred to in the remainder of this chapter as the “substitute determination”.

There are a number of potential benefits of this model over the placeholder with true-up model, including:

- the process to be followed and the decisions that the AER is required to make are in all practical respects equivalent to those it would have to make under a standard regulatory determination process. This includes the consultation process between the preliminary and final determination, which is intended to be the same as that between a standard draft and final determinations;
- the true-up can be seen as analogous to that which is required between a final determination and the outcome of a merits review at the moment, so the concept of this type of true-up is familiar to stakeholders;
- the AER is required to carry out the detailed assessment set out in Chapters 6 and 6A of the NER rather than conducting a high level review of a placeholder value; and
- it avoids a number of measurement issues and rate of return related issues associated with the placeholder with true-up model because the preliminary determination is made before the commencement of the regulatory period and the substitute determination is made shortly thereafter.

A potential shortcoming of this model is, however, that the consultation period is two to three times longer than what would be required for the placeholder determination (six months vs two to three months). It may not therefore be possible to apply in all cases.

The preliminary determination with mandatory re-opener model also has a number of advantages over existing provisions within the NER such as clause 6.11.3(b). This clause states that if a period intervenes between the end of one regulatory control period and the commencement of a new determination, then the prior determination continues in force and appropriate adjustments can be made in the later determination. The advantages that the preliminary determination with mandatory re-opener model has over this clause are that it will:

- allow the new rules to come into effect earlier than clause 6.11.3(b);
- result in prices in the first regulatory year that are more likely to be closer to those established in the substitute determination than what would occur if prices were carried over from the prior determination;
- provide NSPs and other stakeholders with a greater degree of certainty about the rate of return that will apply over the regulatory period before the commencement of the period; and

- avoid a number of measurement issues and the need to have a regulatory determination applying for a partial year (ie 4.5 years).

The consultation period for the transitional rules formally ended on 26 October 2012 and 19 submissions were received. An overview of the views expressed in these submissions is provided in the following section.

Before moving on though, it is worth noting that the Commission is aware that the AER and NSPs have worked collaboratively throughout the consultation period to try and develop an alternative model that is both:

- consistent with the principles set out in section 12.2; and
- simpler to implement and less resource intensive than the model proposed in the consultation paper.

The Commission appreciates the efforts that have been made and values the work that has been done in a short period of time on this complex issue. The Commission would also like to extend its thanks to consumer groups, the AER and NSPs for making themselves available to discuss the transitional arrangements during the consultation period.

## **12.4 Submissions on consultation paper**

Responses to the consultation paper and the proposed transitional arrangements for NSPs were received from the AER, those NSPs affected by the transitional arrangements, the ENA, QTC, the MEU, the Victorian DPI and the ESAA. The topics touched on in these responses can be broadly categorised as relating to:

- the need for transitional arrangements;
- the appropriate model to use for transitional arrangements;
- the operation of incentive schemes during the transitional year; and;
- a range of other ancillary issues.

The remainder of this section contains an overview of the views expressed by stakeholders on each of these topics.

### **12.4.1 Need for transitional arrangements**

Most of the submissions received in response to the consultation paper acknowledge that some form of transitional arrangement is required.<sup>487</sup> However, the following

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<sup>487</sup> See for example, AER, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2; Energex, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 1; MEU, Consultation Paper on Savings and Transitional Arrangements submission, 24 October 2012, pp. 1-2; and SA Power Networks, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p.1.

NSPs question whether the arrangements should be applied to them and, if so, the form the arrangements should take:

- SP AusNet (transmission) contends that the proximity of its next regulatory period with the guideline development process is too close and accordingly, it should be subject to the old Chapter 6A rules for 4.25 years.<sup>488</sup> A 4.25 year period would mean that SP AusNet would become subject to the new rules at the same time as ElectraNet;<sup>489</sup>
- ActewAGL submits that if it is subject to a 12 month delay then it will result in a direct overlap with its gas access arrangement review process and give rise to significant resource constraints.<sup>490</sup> In its initial submission, ActewAGL suggested it should be subject to the old Chapter 6 rules during the next regulatory period.<sup>491</sup> However, in later discussions ActewAGL has suggested that if its electricity regulatory process is to be delayed by 12 months then its gas access arrangement review should also be delayed by the same period;
- CitiPower, Powercor and United Energy prefer to maintain their existing timetables and not be subject to delay.<sup>492</sup> United Energy also questions why resourcing issues for the regulator are allowed to perpetuate for three years;<sup>493</sup> and
- Powerlink and Aurora question the need for transitional arrangements to be applied to them given their next regulatory periods are not due to commence until 2017.<sup>494</sup>

In a similar manner to the last two groups of NSPs, the MEU is of the view that transitional arrangements should only apply to those NSPs that are due to submit their regulatory proposals in 2013, ie SP AusNet (transmission), the NSW DNSPs, ActewAGL, TransGrid and Transend.<sup>495</sup>

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<sup>488</sup> As an alternative, SP AusNet proposes that its revenue in the transitional year should be rolled over from the prior regulatory period with a CPI escalation and that no subsequent true-up should be carried out.

<sup>489</sup> SP AusNet, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, pp. 2-5.

<sup>490</sup> ActewAGL also noted the potential for a retail price review to be carried out in 2013-14.

<sup>491</sup> ActewAGL, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2.

<sup>492</sup> CitiPower and Powercor, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 1 and UE and MG, Consultation Paper on Savings and Transitional Arrangements submission, 26 October 2012, p. 1.

<sup>493</sup> UE and MG, Consultation Paper on Savings and Transitional Arrangements submission, 26 October 2012, p. 1.

<sup>494</sup> Aurora Energy, Consultation Paper on Savings and Transitional Arrangements submission, 29 October 2012, p. 2 and Powerlink, Consultation Paper on Savings and Transitional Arrangements submission, 26 October 2012, p. 2.

<sup>495</sup> MEU, Consultation Paper on Savings and Transitional Arrangements submission, 24 October 2012, pp. 1-2.

## 12.4.2 Model to be used for transitional arrangements

The transitional arrangements set out in the consultation paper did not receive any support from stakeholders.<sup>496</sup> Instead, stakeholders expressed a preference for a placeholder with true-up style model to be used if there was to be a 12 month delay to the full determination process. Different views have, however, been expressed about how the placeholder value should be established. These views can be summarised as follows:

- the AER does not support the use of either the mechanistic or hybrid models because it is concerned that a cap may act as a default position and result in placeholder values that do not reflect efficient costs. The AER is therefore of the view that some level of regulatory consideration of the placeholder value is required and has suggested that a modified version of the TransGrid model be adopted. The differences between the AER's and TransGrid's models principally relate to:
  - the information to be provided by NSPs to support their placeholder proposals, with the AER proposing the provision of more detailed information than TransGrid; and
  - the criteria to be applied by the AER when assessing a NSP's placeholder proposal, with the AER suggesting a number of additional criteria to those proposed by TransGrid.<sup>497</sup>
- TransGrid is of the view that the model it proposed should be used although it acknowledges that the hybrid model may also be appropriate;<sup>498</sup>
- the NSW DNSPs support the use of both the modified version of the TransGrid model proposed by the AER and the hybrid model;<sup>499</sup>

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<sup>496</sup> AER, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2; Transend, Consultation Paper on Savings and Transitional Arrangements submission, 24 October 2012, p. 1; TransGrid, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2; ActewAGL Distribution, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2; Ergon Energy, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 3; Energex, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 1; NSW DNSPs, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 4; and MEU, Consultation Paper on Savings and Transitional Arrangements submission, 24 October 2012, pp. 1-2.

<sup>497</sup> AER, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 8.

<sup>498</sup> TransGrid, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 1.

<sup>499</sup> NSW DNSPs, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, pp. 4-7.

- the Queensland DNSPs, Transend and Jemena support the hybrid model,<sup>500</sup> SA Power Networks is indifferent between the mechanistic and hybrid models<sup>501</sup> and ActewAGL prefers a more mechanistic approach;<sup>502</sup> ;
- CitiPower and Powercor are of the view that NSPs should be able to choose either a mechanistic approach or a propose-consider model. The mechanistic approach proposed by CitiPower and Powercor differs, however, from the mechanistic model described in section 12.3;<sup>503</sup>
- SP AusNet (distribution) is of the view that the placeholder value for the Victorian DNSPs should be based on their first year revenue requirement, as set out in their respective regulatory proposals;<sup>504</sup>
- United Energy submits that it should be able to set prices for the transitional year based on its own circumstances with the objective of minimising future price volatility;<sup>505</sup>
- the MEU prefers TransGrid's proposal but notes the potential for inaccuracy and inequity in the first year;<sup>506</sup> and
- the Victorian DPI is of the view that the placeholder revenue should be determined by rolling forward the approach to determining opex, or otherwise applying a total factor productivity based price path for the first year, or freezing the network charges in real terms with STPIS.<sup>507</sup>

Further detail on the views expressed by stakeholders about specific elements of the placeholder with true-up model is set out below.

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- 500 Energex, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, pp. 1-2; Ergon Energy, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 4; Jemena, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 1; and Transend, Consultation Paper on Savings and Transitional Arrangements submission, 24 October 2012, pp. 1-2.
- 501 SA Power Networks, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2.
- 502 ActewAGL Distribution, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, pp. 1-3.
- 503 CitiPower and Powercor, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 3.
- 504 SP AusNet, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 8.
- 505 UE and MG, Consultation Paper on Savings and Transitional Arrangements submission, 26 October 2012, p. 1.
- 506 MEU, Consultation Paper on Savings and Transitional Arrangements submission, 24 October 2012, p. 2.
- 507 Victorian DPI, Draft Rule Determination submission, 2 November 2012, p. 5.

## True-up mechanism

The following comments were made by stakeholders about how the true-up should be carried out:

- most of the NSPs are of the view that any true-up that is undertaken should be carried out on a NPV neutral basis;<sup>508</sup> and
- the Victorian DNSPs are of the view that the true-up should only be carried out on the rate of return and that no true-up should be carried out for opex and capex.<sup>509</sup>

In further discussions with the AEMC, the AER and SA Power Networks suggested that the final year X factor anchor point (clauses 6.5.9(b)(2) and 6A.6.8(c)(2) of the NER) should be relaxed in the transitional rules so that any true-up that may be required over years 2-5 results in a smooth price path.

## Potential for retrospective decisions on operating and capital expenditure

A number of NSPs have concerns about the potential for the AER to have regard to actual opex and capex data, rather than forecast data, when carrying out its full determination close to the end of the first year.<sup>510</sup>

The AER recognises the potential for this to occur under the placeholder with true-up model but is of the view that this matter can only be addressed if a more substantial process is carried out ahead of the first year, eg the consultation paper approach. The AER notes that, on balance, the industry appears to support the placeholder with true-up model and that most NSPs view the level of uncertainty around opex and capex as manageable, particularly if they are not penalised under an expenditure incentive sharing scheme.<sup>511</sup>

## Rate of return related issues

The manner in which the rate of return should be measured under the placeholder with true-up model was referred to in a number of submissions.

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<sup>508</sup> See for example, Ergon Energy, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 6; NSW DNSPs, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, Attachment 1, p. 1; TransGrid, Consultation Paper on Savings and Transitional Arrangements submission, 8 October 2012; and SA Power Networks, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2.

<sup>509</sup> Jemena, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2; CitiPower and Powercor, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2; and UE and MG, Consultation Paper on Savings and Transitional Arrangements submission, 26 October 2012, p. 1.

<sup>510</sup> See for example, NSW DNSPs, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 3 and Jemena, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, pp. 1-2.

<sup>511</sup> AER, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 9.

Although there appears to be broad consensus amongst interested parties that a single rate of return should apply across the period,<sup>512</sup> different views have been expressed about the period over which the rate of return should be measured, ie before the first year<sup>513</sup> or in the lead up to the second year. Notwithstanding the differences in opinion on this issue, NSPs and the AER appear to see benefits in the framework and approach process being used to:<sup>514</sup>

- identify any market observation period that may be required to measure the rate of return; and
- set out the AER's view on the methodologies that it is likely to accept for the measurement of the return on debt.

Having these matters resolved before the commencement of the first year was viewed by a number of NSPs as being of considerable importance given their financing arrangements.<sup>515</sup>

### 12.4.3 Operation of incentive schemes

The views of stakeholders on whether incentive schemes should operate for the first year vary depending on the incentive scheme, as set out below:

- *Capex sharing schemes and ex post capex review* – there is general consensus amongst NSPs and the AER that capex sharing schemes should *not* operate for the first year.<sup>516</sup> NSPs are also of the view that the AER should not be able to

<sup>512</sup> See for example, QTC, Consultation Paper on Savings and Transitional Arrangements submission, 24 October 2012, p. 2; Ergon Energy, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, pp. 5-6; UE and MG, Consultation Paper on Savings and Transitional Arrangements submission, 26 October 2012, p. 1; and CitiPower and Powercor, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2.

<sup>513</sup> See for example, Ergon Energy, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 5; CitiPower and Powercor, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2; and SA Power Networks, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 4.

<sup>514</sup> AER, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 10; SA Power Networks, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, pp. 3-4; Energex, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2; Ergon Energy, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, pp. 5-6; UE and MG, Consultation Paper on Savings and Transitional Arrangements submission, 26 October 2012, p. 1; and CitiPower and Powercor, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2.

<sup>515</sup> See for example, Ergon Energy, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 5 and SA Power Networks, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 4.

<sup>516</sup> See for example, AER, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 11; Energex, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2; and NSW DNSPs, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, Attachment 1 p. 4.

preclude capex incurred during the current regulatory period from being included in the RAB as part of an ex post efficiency review.<sup>517</sup>

- *Efficiency Benefit Sharing Scheme (EBSS)* - there were mixed views on the EBSS with some NSPs suggesting that it be suspended<sup>518</sup> while other NSPs and the Victorian DPI thought it should operate.<sup>519</sup> The AER has indicated that there is some uncertainty as to the future form of the scheme and that its ongoing application will be considered concurrently with the development of guidelines in 2013. It suggests therefore that the framework and approach paper process be used to set out how the EBSS will apply for the first year. It also suggests that the transitional rules should provide flexibility for the EBSS to apply differently for the first year (eg by setting the target in the first year equal to actual operating expenditure).<sup>520</sup>
- *Service Target Performance Incentive Scheme (STPIS)* - there is broad support amongst stakeholders for the continuation of the STPIS (distribution and transmission).<sup>521</sup>
- *Demand Management and Embedded Generation Incentive Scheme (DMEGCIS)* - there is also broad support amongst stakeholders for the continuation of this scheme.<sup>522</sup>

<sup>517</sup> See for example: ActewAGL Distribution, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 3; ENA, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, pp. 3-4; ESAA, Consultation Paper on Savings and Transitional Arrangements submission, 23 October 2012, pp. 1-2; Jemena, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, pp. 2-3; and UE and MG, Consultation Paper on Savings and Transitional Arrangements, 26 October 2012, p. 2.

<sup>518</sup> CitiPower and Powercor, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 4; SP AusNet, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 6; UE and MG, Consultation Paper on Savings and Transitional Arrangements submission, 26 October 2012, p. 1; SA Power Networks, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 4; and NSW DNSPs, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 3.

<sup>519</sup> Energex, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2; TransGrid, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, Attachment 2 pp. 1-2; and Victorian DPI, Draft Rule Determination submission, 2 November 2012, p. 5.

<sup>520</sup> AER, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 10.

<sup>521</sup> See for example, AER, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 11; SA Power Networks, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 5; Energex, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2; CitiPower and Powercor, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 3; and TransGrid, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, Attachment 2.

<sup>522</sup> AER, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 11; SA Power Networks, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 5; Energex, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2; and NSW DNSPs, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 3.



- *Jurisdictional schemes* - stakeholders agreed that jurisdictional schemes such as the Victorian F-Factor scheme and the NSW D-factor scheme should continue to operate in the first year.<sup>523</sup>

#### 12.4.4 Other ancillary issues

The implementation of both the placeholder with true-up model and the consultation paper model requires a number of ancillary decisions to be made for the first year. The views expressed by stakeholders about how these decisions should be made are summarised in the table below.

**Table 12.1 Treatment of ancillary decisions in transitional year**

Ancillary Decisions	Views of stakeholders
Additional pass through events	The AER, NSW DNSPs, Energex, Ergon, SA Power Networks, CitiPower and Powercor are of the view that these events should be carried over from the current regulatory period.
Negotiating framework	The AER, NSW DNSPs and SA Power Networks are of the view that these elements should be carried over from the current regulatory period.
Negotiated Distribution/ Transmission Service Criteria	
Pricing methodology for transmission	The AER suggests this be dealt with through the framework and approach paper process.
Classification of distribution services	
Form of control mechanism (including X factor) for standard control services and associated formulae	The AER, CitiPower, Powercor, NSW DNSPs and SA Power Networks suggest that this be dealt with through the framework and approach paper process.
Form of control mechanism for alternative control services and associated formulae	The NSW DNSPs suggest that this be dealt with through the framework and approach paper process.
Application of Part J of Chapter 6A to services provided by dual function assets	The AER suggests that this be dealt with through the framework and approach paper process.
Connection policy	The AER, NSW DNSPs and SA Power Networks note that this will need to be dealt with on a jurisdictional basis.
Prices of Alternative Control Services	<p>In a number of submissions a distinction has been drawn between alternative control services that can be subject to a true-up (eg public lighting and metering services) and those that cannot (eg fee and quoted services). For those alternative control services that cannot be subject to a true-up, interested parties expressed the following views:</p> <ul style="list-style-type: none"> <li>• the AER suggests that prices from the prior regulatory period be rolled forward with a CPI adjustment;</li> <li>• CitiPower and Powercor are of the view that prices should be rolled forward at CPI+2% because most of these services are labour rate based and these costs tend to increase at a faster rate than CPI;</li> <li>• Energex suggests that prices may be rolled forward with a CPI adjustment, continue with the existing methodology or use the new rates proposed as part of a pricing proposal; and</li> <li>• Ergon suggests using a hybrid model, so that if the proposed price falls below a cap it is automatically approved but if it is above the cap the AER must review the proposed price.</li> </ul>

Sources: AER, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, pp. 10-12; Energex, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2; Ergon Energy, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 5; SA Power Networks, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, pp. 3-5; CitiPower, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, pp. 2-4; and NSW DNSPs, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, pp. 3-4.

<sup>523</sup> Id., p. 12; CitiPower and Powercor, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, pp. 2,4.

## 12.5 Guideline development process

In the draft rule determination and draft rules the Commission set out detailed timetables for the development of the various guidelines that the AER is required by the new rules to produce.

On reflection, the Commission is of the view that the AER should have some flexibility to manage its work programme and determine the dates by which key milestones will be achieved in respect of the guidelines. The transitional rules therefore only require the first version of these guidelines to be finalised by 29 November 2013.

To provide NSPs and other stakeholders with sufficient notice and certainty upfront, the transitional rules also require the AER to publish a statement by 21 December 2012 that sets out:

- a proposed schedule, including milestones and key dates, for the making of the various guidelines; and
- the specific consultation procedure to be followed, which must at a minimum be consistent with the requirements of the distribution or transmission consultation procedures (as applicable).

It is worth noting in this context that 29 November 2013 is the final date by which the AER will be required to publish the guidelines and that it may publish various guidelines in advance of that date.

## 12.6 Need for transitional arrangements

This final rule determination provides for a number of significant changes to Chapters 6 and 6A of the NER and also requires the AER to develop a number of guidelines by 29 November 2013. Although these guidelines will not be binding, they are intended to play an integral role in the regulatory review process going forward for the following reasons:

- service providers, the AER and the appeal body will be required to have regard to them in the context of each regulatory determination; and
- if a service provider or the AER wishes to depart from the approaches set out in the guidelines, they will be required to clearly set out the reasons for the proposed departure.

At the same time as the AER is developing the various guidelines, seven NSPs are due to submit their regulatory proposals (see table below). Another eight NSPs are due to submit their proposals within 12 months of the date by which the guidelines are to be finalised. Given the degree of overlap between the guideline development and regulatory determination processes, some form of transitional arrangement is required to:

- enable the new rules and guidelines to be applied in the next round of regulatory reviews; and
- minimise the resourcing burden that the guideline development and regulatory determination processes may otherwise place on the AER, NSPs and other stakeholders.

**Table 12.2 Existing timetable for regulatory determinations**

NSP		Framework and Approach Paper	Regulatory Proposal Due	Regulatory Period Commences
ElectraNet and Murraylink (SA transmission and interconnector between Vic and SA)		n.a.	Already submitted	1 July 2013
SP AusNet (Vic transmission)		n.a.	28 February 2013	1 April 2014
2014 Group of NSPs	TransGrid and Transend (NSW and Tas transmission)	n.a.	31 May 2013	1 July 2014
	ActewAGL, Ausgrid, Endeavour Energy and Essential Energy (ACT and NSW distribution)	30 November 2012	31 May 2013	1 July 2014
Directlink (Interconnector between Qld and NSW)		n.a.	31 May 2014	1 July 2015
2015-2016 Group of DNSPs	Ergon, Energex and SA Power Networks (Qld and SA distribution)	30 November 2013	31 May 2014	1 July 2015
	Jemena, United Energy, CitiPower, Powercor and SP AusNet (Vic distribution)	31 May 2014	30 November 2014	1 January 2016
Post 2016 Group	Aurora Energy (Tas distribution)	30 November 2015	31 May 2016	1 July 2017
	Powerlink (Qld transmission)	n.a.	31 May 2016	1 July 2017
	ElectraNet (SA transmission)	n.a.	31 May 2017	1 July 2018
	Murraylink (Interconnector between SA and Vic)	n.a.	31 May 2022	1 July 2023

From the submissions that have been made on this issue, it would appear that most interested parties accept that some form of transitional arrangement is required for a number of the NSPs listed in Table 12.1. However, concerns have been expressed about the scope of the proposed arrangements outlined in the consultation paper and the length of time over which transitional arrangements are expected to persist. The Commission has therefore given further consideration to both:

- the period over which the transitional arrangements should apply and the NSPs that should be subject to the arrangements; and
- the form(s) that the transitional arrangements should take.

The Commission's analysis of these two matters is set out in the remainder of this chapter.

## **12.7 NSPs that will be subject to the transitional arrangements**

In the consultation paper it was envisaged that all NSPs, except ElectraNet, Murraylink and Directlink, would be subject to the same form of transitional arrangements and that the transitional rules would need to operate for at least five years. The persistence of the arrangements through to 2017 was, at this stage, considered necessary to minimise any resourcing constraints that the AER, NSPs and other stakeholders may face during the guideline development and regulatory review processes.

Following the receipt of a number of submissions on this issue, the Commission has given further consideration to the need to have the transitional rules in operation for this length of time. To this end, the Commission has worked with the AER to determine whether, from an AER resourcing perspective,<sup>524</sup> transitional arrangements are required until 2017.

On the basis of the discussions the Commission has had with the AER and the Commission's own analysis, it would appear that:

- a delay of more than 12 months will be required for SP AusNet (transmission) given the proximity of the commencement of its next regulatory period to the last date by which the AER is required to finalise its guidelines;
- a 12 month delay to the full determination process will be required for those NSPs that are due to commence their next regulatory period on 1 July 2014;
- some form of transitional arrangement will be required for those NSPs that are currently due to commence their next regulatory period on 1 July 2015 and 1 January 2016 but a five month delay to the full determination process would be sufficient if certain elements of the extended consultation process were excluded;
- Directlink can follow a regulatory determination process in accordance with its existing timetable; and
- no transitional arrangements are required for NSPs with regulatory periods commencing post 2016, ie Aurora, Powerlink, ElectraNet and Murraylink.

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<sup>524</sup> It is worth noting in this context that the potential for resourcing constraints within the AER exists because regulatory processes are currently staggered. A delay in the regulatory process for one group can therefore create an overlap with other regulatory processes.

The Commission has therefore decided to:

- exclude Aurora, Powerlink, ElectraNet and Murraylink from the transitional arrangements<sup>525</sup> and to require them to be subject to the new rules from the commencement of their next regulatory periods;
- apply different transitional arrangements to the following groups of NSPs:
  - SP AusNet (transmission), which is due to commence its next regulatory period on 1 April 2014;
  - ActewAGL, Ausgrid, Endeavour Energy, Essential Energy, TransGrid and Transend, all of which are due to commence their next regulatory periods on 1 July 2014 (referred to in this chapter as the “2014 group of NSPs”);
  - – Energex, Ergon, SA Power Networks, CitiPower, Jemena, SP AusNet (distribution), Powercor and United Energy (referred to in this chapter as the “2015-2016 group of DNSPs”). The first three of these DNSPs are due to commence their next regulatory periods on 1 July 2015 while the latter five are due to commence their next regulatory periods on 1 January 2016; and
  - Directlink, which is due to commence its regulatory period on 1 July 2014.

The Commission’s final decision on the form of the transitional arrangements that will be applied to SP AusNet (transmission), the 2014 group of NSPs, the 2015-2016 group of DNSPs and Directlink is set out in the following sections.

## **12.8 Form of the transitional arrangements to be applied to NSPs**

As outlined above, the key driver of the transitional arrangements is the requirement for the AER to develop guidelines as a basis for applying the new rules. This means that the more time that has elapsed since the guidelines have been finalised, the easier it should be for stakeholders to transition to the new rules. To put it another way, those NSPs whose regulatory proposals would, in the absence of transitional rules, have been due during, or shortly after, the completion of the AER’s guidelines will require more significant transitional arrangements than those with regulatory proposals due at a later point in time.

The decline in the need for the transitional arrangements is reflected in the Commission’s approach to SP AusNet (transmission), the 2014 group of NSPs and the 2015-2016 group of DNSPs.

SP AusNet (transmission), whose next regulatory period is due to commence four months after the last date by which the AER’s guidelines are to be finalised, requires the most significant transitional provisions because there is insufficient time for even a

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<sup>525</sup> The only transitional rules that will apply to this group of NSPs are the provisions relating to the time at which the AER can review capex, for the purposes of identifying inefficient capex, non-arm’s length margins and/or expenditure that is capitalised inappropriately.

truncated regulatory process. The existing rules must therefore be preserved for SP AusNet for a period of time. After considering a range of options, the Commission has decided that SP AusNet should be subject to the existing rules for three years before moving to the new rules on 1 April 2017.

For the 2014 group of NSPs and the 2015-2016 group of DNSPs, less significant transitional arrangements are required than for SP AusNet. In particular, it is possible for the existing timing of the regulatory periods to be maintained and for the AER's resourcing issues to be accommodated by delaying the AER's "full" determination for a period of time and using an "interim" determination for the first year of the period. For the 2014 group of NSPs the AER's "full" determination will need to be delayed by 12 months while the 2015-2016 group's determination will only need to be delayed by five months.

During the consultation process, a range of options for dealing with a delay in the 'full' determination process were canvassed (see section 12.3). Given the concerns that have been raised with the proposal set out in the consultation paper, the Commission has given further consideration to two of the other options that were canvassed during this process, ie the placeholder with true-up model and the preliminary determination with mandatory re-opener model.

As noted in section 12.3, the preliminary determination with mandatory re-opener model has a number of advantages over the placeholder with true-up model but it requires a longer consultation period than is available to the 2014 group of NSPs.<sup>526</sup> The Commission has therefore decided to apply the placeholder with true-up model to this group of NSPs.

In contrast to the 2014 group of NSPs, a five month delay to the 2015-2016 group of DNSPs' regulatory determination process will provide the AER with sufficient time to make a preliminary determination before the commencement of the regulatory period. Given the advantages that this model has over the placeholder with true-up model, the Commission has decided to apply the preliminary determination with mandatory re-opener model to this group of NSPs.

In the case of Directlink, the AER has indicated that it has sufficient resources to carry out its regulatory determination in accordance with its existing timetable.<sup>527</sup> Transitional arrangements are therefore only required to deal with the length of Directlink's regulatory determination process and the timing of its framework and approach paper process.

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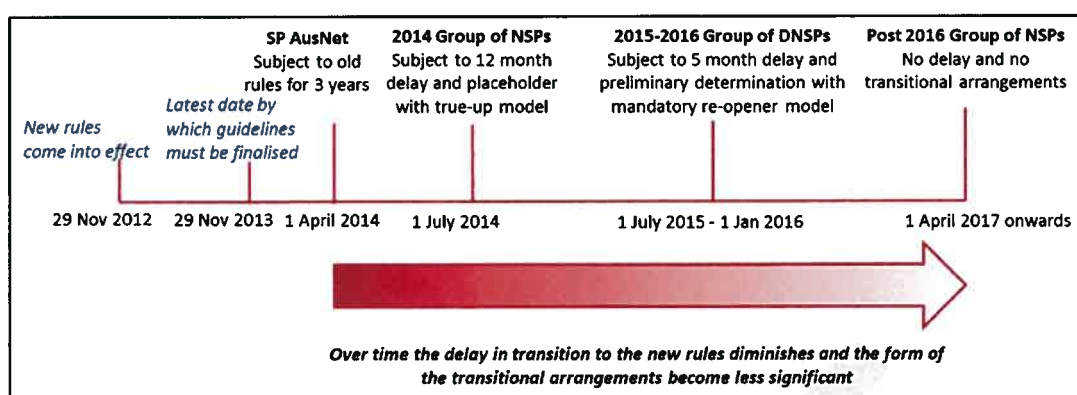
<sup>526</sup> The application of this model would require a NSP to submit its regulatory proposal to the AER eight months before the regulatory period commences. There are, however, only seven months between the latest date by which the AER is required to finish its guidelines and when this group's regulatory period starts. The period would be even shorter if any provision was made for the NSPs to take account of the guidelines in their regulatory proposals.

<sup>527</sup> AER, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2.

For those NSPs with regulatory periods commencing post 2016, no transitional arrangements are required. Aurora, Powerlink, ElectraNet and Murraylink will therefore be subject to the new rules at the commencement of their next regulatory periods.

The form of the transitional arrangements that will be applied to each of the NSPs is summarised in the figure below.

**Figure 12.1 Transitional arrangements continuum**



As this figure demonstrates, the transitional arrangements that the Commission has decided to put in place may be viewed as a continuum with the time taken to transition to the new rules and the differences between the standard determination process and the transitional determination process diminishing over time.

The remainder of this chapter provides further detail on the Commission's rationale for adopting these transitional arrangements and how it intends them to be applied to SP AusNet (transmission), the 2014 group of NSPs, the 2015-2016 group of NSPs and Directlink.

Before moving on though, it is worth noting that in designing these arrangements the Commission has been mindful of the uncertainty and, in some cases, additional burden that the transitional arrangements may place on stakeholders. Given that in some cases it will be over a year until the transitional arrangements are applied, it may be that as time passes stakeholders view the need for transitional arrangements differently. For example, if the AER's resourcing was to change there may no longer be a need for transitional arrangements for the 2015-2016 group of DNSPs. It is not possible to provide flexibility for this in the rules.

## 12.9 Transitional arrangements to apply to SP AusNet (transmission)

SP AusNet (transmission) is currently due to submit its regulatory proposal to the AER by 28 February 2013 and commence its next regulatory period on 1 April 2014. At the same time that SP AusNet is due to submit its regulatory proposal, the AER will be developing the guidelines. Given the coincidence of SP AusNet's regulatory determination process and the guideline development process, some form of

transitional arrangement is required to allow the new rules and guidelines to be applied to SP AusNet before the commencement of the subsequent regulatory period.

The four options the Commission has considered in this context are to delay SP AusNet's transition to the new rules by one, two, three or, as requested by SP AusNet,<sup>528</sup> 4.25 years. The Commission's views on each of these options can be summarised as follows:

- A one year delay would result in the fastest transition to the new rules. However, this option would require SP AusNet to submit its regulatory proposal within three months of the latest date by which the AER is required to finalise its guidelines. This three month period would not allow sufficient time for the framework and approach process to be carried out and would mean that other elements of the stakeholder consultation process could not be carried out. This option is therefore contrary to the second principle set out in section 12.2.
- The two year delay option overcomes the deficiencies of the first option. However, a delay of this length would mean that SP AusNet's transmission regulatory determination process would be carried out concurrently with its distribution regulatory determination process. This option is therefore likely to give rise to resourcing constraints within both SP AusNet and the AER and, in so doing, contravene the fourth principle set out in section 12.2
- The three year delay option overcomes the deficiencies identified with the one and two year delay options. It also has better incentive properties because it provides a longer regulatory period over which SP AusNet can seek out efficiencies that will benefit consumers in future regulatory periods. The one drawback of this option is, however, that it results in a slower transition to the new rules.
- The final option, which is to delay the transition to the new rules by 4.25 years, also overcomes the deficiencies identified with the first two options. However, in the Commission's view this is too long a period to wait for SP AusNet to transition to the new rules and is inconsistent with the first principle set out in section 12.2.

On balance, the Commission is of the opinion that the three year delay option is more consistent with the principles set out in section 12.2 than the other three options and that the benefits of this option outweigh the delayed transition to the new rules. SP AusNet's transmission determination will therefore be made for the period 1 April 2014 - 31 March 2017 under the older Chapter 6A rules. A new transmission determination will then be made under the new Chapter 6A rules for the regulatory period commencing on 1 April 2017.

To put this decision into context, it is worth noting that although SP AusNet will be subject to the old rules for another three years, it will be required to transition to the

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528 SP AusNet, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 5.



new rules before Powerlink and ElectraNet (1 April 2017 vs 1 July 2017 and 1 July 2018). This decision is therefore consistent with the Commission's broader objective of having the new rules come into effect before the commencement of the subsequent round of regulatory determinations.

## **12.10 Transitional arrangements to apply to 2014 group of NSPs**

ActewAGL, Ausgrid, Endeavour Energy, Essential Energy, TransGrid and Transend are due to submit their regulatory proposals to the AER by 31 May 2013 and commence their next regulatory period on 1 July 2014. At the time this group of NSPs regulatory proposals are due to submit their regulatory proposals, the AER will not have finalised its guidelines. To enable the new rules and guidelines to be applied to this group of NSPs in the next regulatory period, a 12 month delay to the full regulatory determination process is required.

Having considered a number of options for dealing with the 12 month delay, the Commission has come to the view that the placeholder with true-up model should be applied to this group of NSPs (see section 12.8). Under the placeholder with true-up model, the AER will be required to:

- conduct a high level review of a NSP's proposed revenue requirement for the transitional year (year 1) and make a binding determination 2-3 months before the commencement of that year (referred to in the remainder of this chapter as the "placeholder determination");
- make a full determination during the transitional year, for years 2-5<sup>529</sup> and the transitional year and use a NPV neutral true-up mechanism to account for any difference between:
  - the placeholder revenue for the transitional year; and
  - the revenue requirement for the transitional year that is established through the full determination process.

It is worth noting in this context that the true-up mechanism is an integral element of this model and will, in effect, allow the new rules and guidelines to be applied to both the transitional year and years 2-5. The inclusion of this mechanism in the model also means that a higher level and less time consuming assessment of the 2014 group of NSPs' transitional year revenue requirements can be undertaken in advance of the transitional year. The application of this model should therefore, go some way to alleviating resourcing constraints that may otherwise exist in 2013-14 for the AER and affected NSPs.

To give effect to the placeholder with true-up model, the transitional rules provide for the following regulatory periods:

- the transitional regulatory period, which will operate over the period 1 July 2014 to 30 June 2015; and;
- the subsequent regulatory period, which will operate over the period 1 July 2015 to 30 June 2019.<sup>530</sup>

The remainder of this section sets out how the Commission intends the placeholder with true-up model to be applied to this group of NSPs, with particular emphasis placed on:

- the placeholder determination process;
- the full determination process;
- the extent to which incentive schemes will operate in the transitional regulatory period;
- the matters to be dealt with by the AER through the framework and approach paper process; and
- the manner in which a range of ancillary issues will be treated for the transitional regulatory period.

#### 12.10.1 Placeholder determination process

As its name suggests, the placeholder determination requires the AER to conduct a high level review of the 2014 group of NSPs' proposed revenue requirements for standard control and prescribed transmission services for the transitional regulatory period.

Given the nature of the placeholder determination and the limited time available, the transitional rules require:

- a relatively short consultation process, with the AER having just two to three months<sup>531</sup> to make the placeholder determination (see table below);
- the NSPs to provide the AER with indicative estimates and ranges for certain building block elements; and

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529 In accordance with the transitional rules, the AER is required to approve a subsequent regulatory period of four years but a NSP may, with the AER's agreement, have a subsequent regulatory period of no less than three years or more than four years.

530 This assumes a regulatory period of four years for the subsequent regulatory period.

531 The consultation period for TNSPs is one month shorter than for DNSPs because rule 6A.24.4 states that if the AER has not made a final decision on the revenue proposal by a date that is three months prior to the commencement of the first pricing year then the draft decision will apply. Given that there will be no draft placeholder determination, the AER will be required to publish the TNSPs placeholder determination three months before the commencement of the transitional regulatory control period so that it can be used to set prices for that year.

- the AER to apply relatively high level criteria when assessing a NSP's proposal, rather than undertaking the detailed assessment that would usually be required by Chapters 6 or 6A of the rules. Put another way, the AER is not required to justify its decision about the placeholder revenue by applying a building block model to estimate a NSP's placeholder revenue requirement.

Further detail on the latter two of these aspects of the placeholder determination is set out below.

**Table 12.3 Key Dates for the Placeholder Determination Process**

NSP	Submission of Transitional Regulatory Proposal to the AER	AER Invites Written Submissions	AER Determination
TransGrid and Transend	31 January 2014	As soon as practicable	31 March 2014
ActewAGL and NSW DNSPs			30 April 2014

#### Information to be provided to the AER

Five months prior to the commencement of the transitional regulatory period, the 2014 group of NSPs will be required to provide the AER with a transitional regulatory proposal, which sets out their proposed revenue requirement for the transitional year. These NSPs will also be required to provide the following supporting information to the AER:

- an indicative estimate of the opening value of the RAB at the beginning of the transitional year;
- an indicative range for the rate of return, which has regard to the AER's rate of return guidelines, and takes into account available market information and expected market trends;
- an indicative estimate of forecast opex, capex, depreciation and corporate tax for the transitional year;
- the revenue that the NSP expects to earn from the provision of standard control or prescribed transmission services in the last year of the current regulatory period and an indicative range of its revenue requirements for the provision of those services for the transitional year and for the subsequent four years;
- a summary of the NSP's proposed expenditure for the transitional year and the subsequent four years and an explanation of how the proposal is consistent with the placeholder revenue; and
- any other information the NSP considers relevant to the AER's determination.

The transitional rules also require DNSPs that are subject to a price cap to provide the AER with indicative estimates of demand for each type of direct control service for the transitional year and the subsequent four years.

### Criteria to be applied by the AER

The AER will be required to publish its final determination for the transitional regulatory period two months after receiving a TNSP's transitional regulatory proposal and three months after receiving a DNSP's proposal.<sup>532</sup>

The AER will only be able to approve a NSP's proposed placeholder revenue proposal if it is satisfied that:

- the amount set out in it is likely to be consistent with the NEO and the RPP; and
- recovery of that amount is reasonably likely to minimise price variations between the current regulatory control period, the transitional regulatory control period and the subsequent regulatory control period and between regulatory years.

In deciding whether or not to approve a NSP's proposed placeholder, the AER is also required by the transitional rules to have regard to the following:

- the fact that the revenue requirement for the transitional regulatory period is an estimate that is based on indicative inputs, and that the determination for the next regulatory period will provide for a true-up;
- the information included in, or accompanying, the transitional regulatory proposal;
- submissions received in the course of consulting on the transitional regulatory proposal; and
- analysis undertaken by, or for, the AER in connection with the transitional regulatory proposal.

If the AER does not approve a NSP's placeholder proposal, it must approve an amount that it is satisfied is consistent with the NEO and RPP and that recovery of which is reasonably likely to minimise price variations between regulatory control periods and regulatory years.

It is worth noting in this context that the AER is already required by section 16 of the NEL to have regard to both the NEO and the RPP when performing an economic regulatory function. The only additional criterion that the transitional rules require the AER to have regard to is therefore the "reasonably likely to minimise price variations" criterion. This criterion has been incorporated in the transitional rules to minimise the potential for the placeholder determination to result in one off price shocks. Further insight into the Commission's rationale for including this criterion in the transitional rules can be found in section 2.4-2.6.

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<sup>532</sup> Ibid.

### **Pricing of alternative control services by DNSPs**

The preceding discussion has focused on how the revenue requirement for standard control and prescribed transmission services will be determined for the transitional regulatory period. In addition to providing standard control services, the NSW DNSPs and ActewAGL provide alternative control services.

The Commission understands that some forms of alternative control services are capable of being trued-up (eg public lighting and metering) while others are not (eg fee and quoted services). The transitional rules therefore provide for:

- the control mechanism currently applying to these services to be maintained for the transitional regulatory period, unless otherwise amended through the framework and approach paper;
- prices for these services to be rolled forward from the current regulatory period with a CPI adjustment; and
- where relevant, the AER to set out how any true-up will be carried out in the full determination process in the framework and approach paper for ActewAGL and the NSW DNSPs.

#### **12.10.2 Full determination**

The full regulatory determination process for the 2014 group of NSPs will be carried out during the transitional regulatory control period and the AER will be required to publish its final determination just before the commencement of the first year of the subsequent regulatory control period (year 2). The full determination will be carried out, with some exceptions, in accordance with the new rules and guidelines and will establish:

- the NSP's annual revenue requirement for the subsequent regulatory control period (years 2-5);
- the annual revenue requirement that would have been established for the transitional regulatory control period (year 1) if it had been subject to a full determination process; and
- the amount of any true-up that is required in years 2-5 to account for differences between the placeholder revenue and the transitional year revenue requirement established through the full determination process.

Further detail on the following matters is provided below:

- the consultation process for the full determination;
- the manner in which the true-up will be carried out;
- transitional year measurement issues;

- the manner in which the rate of return will be measured; and
- the length of the subsequent regulatory period.

### Consultation process

Given the timing of the guideline development process, there is insufficient time for the 2014 group of NSPs to be subject to the extended regulatory determination process (15 months). The regulatory process for this group of NSPs will therefore be based on an 11 month regulatory process.<sup>533</sup>

Although a shorter regulatory process will be employed, the AER will still be required to publish a framework and approach paper for each NSP and conduct a mandatory public forum on their regulatory proposals. The NSPs will also be required to submit an overview paper when lodging their regulatory proposal and will be subject to the new rules that are intended to increase the level of customer engagement by NSPs on their regulatory proposal.

The key dates for the framework and approach paper, the submission of the regulatory proposal and the publication of decisions are set out in the table below.

**Table 12.4 Key Dates for Full Regulatory Determination Process**

NSP	Framework and Approach Paper Finalised	Regulatory Proposal Due	Final Decision
TransGrid and Transend	31 January 2014	31 May 2014	30 April 2015
ActewAGL and NSW DNSPs	Part 1: 31 March 2013* Part 2: 31 January 2014		

\* The framework and approach paper for ActewAGL and the NSW DNSPs will be split into two, with the first part dealing with matters that are not the subject of guidelines and the second part dealing with the remaining matters (see section 12.10.4. for further detail).

### True-up mechanism

The true-up mechanism is an integral element of the placeholder with true-up model and will be used to account for any deviation between.<sup>534</sup>

- the placeholder revenue for standard control services or prescribed transmission services (as the case may be) in the transitional year; and
- the revenue requirement for standard control services or prescribed transmission services (as the case may be) for the transitional year established through the full determination process.

<sup>533</sup> Two of the more notable elements of the new regulatory process that will not apply to this group of NSPs are the issues paper and the cross-submission process.

<sup>534</sup> It is worth noting that the description of the true-up mechanism in this context assumes that a NSP is subject to a revenue cap. For those DNSPs that are subject to a price cap, the transitional rules require the AER to set out how the true-up will be carried out in its framework and approach paper.

To the extent that it is relevant, a separate true-up mechanism will also be used for the NSW DNSPs and ActewAGL to account for any differences between the alternative control service prices applying in the transitional regulatory period and the prices established through the full determination process.

To the extent that there is an amount that needs to be true-up, the transitional rules require the AER to adjust a NSP's revenue requirements in years 2-5. The transitional rules also require the AER to carry out the true-up on a NPV neutral basis.

The final matter that the Commission has considered in this context is whether the requirement for a final year X factor anchor point (clauses 6.5.9(b)(2) and 6A.6.8(c)(2) of the NER) should be removed for the purposes of the transitional rules.

The Commission understands that, in principle, the final year anchor point is intended to minimise price shocks that may otherwise occur between the final year of the regulatory period and the first year of the subsequent regulatory period. However, under both the placeholder with true-up model and the preliminary determination with mandatory re-opener models, the requirement to carry out a true-up in years 2-5 could result in price volatility within this period if the anchor point is maintained.<sup>535</sup> The Commission has therefore decided, for the purposes of the transitional rules only, to relax this anchor point.

It is worth noting in this context that while the final year anchor point will be removed in the transitional rules,<sup>536</sup> the X factor provisions in Chapters 6 and 6A of the NER will still require the smoothed revenue to be equal to the NPV of the annual revenue requirement (clauses 6.5.9(b)(3) and 6A.6.8(c)(1)). That is, the required revenue can still be recovered across the period, but the smoothing can be applied more optimally.

### **Transitional year measurement issues**

One matter that received some attention during the consultation process was whether, when making its decision on the transitional year revenue requirement during the full determination process, the AER should be able to have regard to:

- information available up to the date it makes the full determination, ie during the transitional year; or
- only information available up to the commencement of the transitional year.

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<sup>535</sup> The potential for this to occur can be seen in the following example, which assumes that prices are originally expected to move from \$100 to \$110 over the five years, demand is constant over the period and the operation of the true-up mechanism results in prices in years 2-5 having to rise by \$20 per annum. In this example the final year anchor point effectively locks in the \$110 price in year 5. The \$20 increase that should have occurred in year 5 must then be spread over years 2-4, resulting in an additional increase in these three years. Over the five year period, prices would therefore move as follows: Year 1: \$100; Years 2-4: greater than \$120; and Year 5: \$110. If the anchor point had been relaxed then prices could have moved up from \$100 to \$120 and remained at this level for the remaining four years rather than moving to a level above \$120 and then moving back down to \$110 in the final year.

<sup>536</sup> Clauses 6.5.9(b)(2) and 6A.6.8(c)(2)

To determine how significant this issue is likely to be, the Commission has considered the information that is likely to be available to the AER when it makes its full determination.

At the time the AER is to make its decision on opex and capex allowances, it is unlikely to have much (if any) data on the expenditure actually incurred by NSPs in the transitional year. The risk of the AER having regard to new information when setting the allowances for these two elements is therefore expected to be quite low. Even if some information was available it would only be expenditure for part of the year, so the weight that the AER could place on such information is likely to be quite low.

Unlike opex and capex, rate of return parameters and other economic indicators used in the derivation of a NSP's revenue requirement are available on a more frequent basis. It is possible therefore that certain elements of the AER's full determination could differ from what they would otherwise have been if the determination had been made one year earlier.

This is a shortcoming of the placeholder with true-up model. However, it is not, in the Commission's view, sufficient enough to warrant a departure from the model, particularly given the benefits that the model offers in terms of ameliorating resource constraints and providing for a faster transition to the new rules. The Commission has therefore considered alternative options for addressing this issue.

The options that the Commission has explored include:

1. Requiring the AER to make a decision in advance of the transitional regulatory period on those elements of the NSP's revenue requirement that could differ if measured before or after the commencement of this period, ie rate of return, inflation and other escalators, and locking this in for the purposes of the full determination;
2. Including a provision within the transitional rules that restricts the AER's assessment during the full determination process to information and data available in the lead up to the transitional year. In effect, this option would require the AER to ignore any information or data released in the ten month period between the commencement of the transitional year and the date on which it makes its final determination; or
3. Leaving it to the AER to exercise its judgement, having regard to both the NEO and RPP.

The problem with the first of these options is that there is insufficient time between the likely release of the AER's guidelines and the commencement of the transitional regulatory period for the level of consultation that would be required to make a decision of this nature. The Commission has therefore rejected this option.

The second option is also problematic because trying to restrict the AER to considering data and information that was available 10 months before it makes its full determination is likely to be difficult to implement in practice. Another shortcoming of



this option is that it could result in substantial resources being dedicated by the NSPs and the AER (and potentially an appeals body) to distinguishing between information and data that was available before or after the commencement of the transitional year. Of greater significance though, is the potential for the adoption of this option to result in a decision that is inconsistent with the NEO and RPP.<sup>537</sup> Given these shortcomings, the Commission has also rejected this option.

The final option is to leave the decision to the AER and allow it to be guided by the NEO and RPP. In the Commission's opinion, this is the most practical solution given:

- the limited time available in the lead up to the transitional year;
- the difficulties associated with not being able to take into account relevant information; and
- the more fundamental need to ensure that regulatory decisions are consistent with the NEO and RPP.

Since section 16 of the NEL already requires the AER to have regard to these matters when performing an economic regulatory function or powers, no transitional rules are required to give effect to this option.

### Measurement of the rate of return

Another issue that was raised during the consultation process was how the rate of return should be measured over the transitional and subsequent regulatory periods.

There was general consensus amongst the AER and the NSPs that a single rate of return should apply across the two regulatory periods rather than two separate rates of return for each period.<sup>538</sup> However, different views were expressed about the period over which the rate of return to apply over the five years should be measured, ie in the lead up to the transitional year or in the lead up to year 2. Notwithstanding the differences in opinion on this issue, the AER and NSPs appear to see benefits in a framework and approach paper process being used to:<sup>539</sup>

<sup>537</sup> For example, if the rate of return rose by 2% in the lead up to the full determination and this was ignored then it may, depending on the financial arrangements the NSP had in place, be argued that the AER's decision did not provide the NSP with an opportunity to recover at least efficient costs (section 7A(2) of the NEL).

<sup>538</sup> See for example, QTC, Consultation Paper on Savings and Transitional Arrangements submission, 24 October 2012, p. 2; Ergon Energy, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, pp. 5-6; UE and MG, Consultation Paper on Savings and Transitional Arrangements submission, 26 October 2012, p. 1; and CitiPower and Powercor, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2.

<sup>539</sup> AER, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 10; SA Power Networks, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, pp. 3-4; Energex, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2; Ergon Energy, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, pp. 5-6; UE and MG, Consultation Paper on Savings and Transitional Arrangements submission, 26 October 2012, p. 1; and CitiPower and

- specify any market observation period that may be required under the AER's rate of return guidelines, to measure the rate of return; and
- set out the AER's view on the methodologies that it is likely to accept for the measurement of the return on debt component of the overall rate of return.

The Commission understands the desire of both the AER and the NSPs to have a single rate of return applying over the two regulatory periods and nothing in the transitional rules precludes this.

The Commission also recognises the desire of NSPs to have some degree of certainty about how the return on debt is likely to be measured before they undertake any refinancing or hedging. However, the new rules do not prescribe the way that the AER must estimate the rate of return beyond being required to achieve an overall rate of return objective. Furthermore, the new rules do not require the approach to estimating the rate of return to involve the use of an averaging period or return on debt methodology to be specified in advance of a regulatory determination. The Commission is reluctant therefore to make a transitional rule that will mandate an approach that is not required by the new rules and which may pre-empt the approach the AER ultimately adopts in its guidelines.

Although the Commission has decided not to deal with this issue through the transitional rules it is of the view that, to the extent it is relevant under the AER's approach for estimating the rate of return in its guidelines, the AER could use the existing framework and approach paper process<sup>540</sup> to consult with NSPs on:

- any measurement period that may be required to measure the rate of return; and
- the methodologies that it intends to employ when measuring the rate of return.

The Commission understands from the following statement contained in the AER's submission that it has already given some consideration to this issue and may be willing to use the framework and approach paper process for this purpose: <sup>541</sup>

'To allow for efficient debt risk management, it is important that the determination process accommodates sufficient and timely certainty in terms of key approaches and processes. Accordingly, the published Framework and Approach paper could appropriately be used to establish any necessary processes for determining the rate of return, such as the timing of any 'sampling period'.'

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Powercor, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2.

<sup>540</sup> Note that the framework and approach paper provisions in Chapters 6 and 6A already allow the AER to use the framework and approach paper to set out its likely approach to any matter that it thinks fit to give an indication on. No specific transitional rules are therefore required to direct the AER to deal with this issue through the framework and approach paper process.

<sup>541</sup> AER, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 10.

### **Length of the subsequent regulatory period**

To enable the combined length of the transitional and subsequent regulatory periods to be five years, the transitional rules allow for the use of a four year regulatory period for the subsequent regulatory period.

The transitional rules also allow the 2014 group of NSPs to propose, and permit the AER to approve, a regulatory period of three or more years. This provision has been incorporated into the transitional rules to enable the NSPs and the AER to optimise the alignment of regulatory reviews across all NSPs. Although the Commission views the alignment of particular regulatory determinations as a separate issue from the transitional arrangements, it understands that it may be desirable from both a resourcing and benchmarking perspective, to allow certain groups of NSPs to be subject to a regulatory review at the same time. It has therefore decided to make provision for this to occur in the transitional rules.

### **12.10.3 Operation of incentive schemes in the transitional year**

Incentive schemes are applied to individual NSPs through the regulatory determination process. The targets for these schemes, or the basis upon which they are calculated, are set out in the final determination for each NSP. As these schemes are intended to drive a particular form of behaviour by NSPs (such as maintaining and improving service standards) the targets for the schemes are required to be known prior to the relevant period. As outlined above, a full regulatory determination will not be made for the transitional year until well into that year for the 2014 group of NSPs. Transitional arrangements are therefore required to deal with incentive schemes for these NSPs.

In its consultation paper the Commission suggested that incentive schemes should not operate in the transitional year as a means of reducing the number of decisions the AER would be required to make for the transitional year determination.<sup>542</sup> Following the receipt of a large number of submissions on this issue, the Commission has reconsidered this proposal.

In short, the Commission is of the view that incentive schemes should, to the extent that it is practical and appropriate to do so, apply in the transitional regulatory period. To account for those cases where it may not be appropriate to apply particular schemes in the transitional year, or where a different method may be required in that year, the Commission is of the view that the AER should have sufficient flexibility to deal with this through the framework and approach paper process. The transitional rules therefore require the AER to set out in the framework and approach paper how the schemes will apply in the transitional regulatory period and in the subsequent regulatory period.

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<sup>542</sup> AEMC, Consolidated Rule Request – Economic Regulation of Network Service Providers, Consultation Paper on Savings and Transitional Arrangements, 14 September 2012, p. 13.

Before setting out the Commission's views on the particular schemes, it is worth noting the following general points:

- the framework and approach paper will be issued before the start of the transitional regulatory period. NSPs should therefore be able to respond to the incentives created by the schemes in the transitional year;
- the AER will not be able to go back and revisit the targets and values that it sets for the transitional year through the framework and approach paper; and
- where rewards/penalties (revenue increments/decrements) from incentive schemes are accrued in the current regulatory period and due to be applied in the transitional year, these will be accounted for in the following regulatory years as part of the true-up mechanism. This includes for example the s-factor.

The Commission's views on each of the schemes are set out below.

The proposed varied STPIS for transmission and the existing STPIS for distribution can apply in some form for the transitional year. The Commission notes that the AER and NSPs broadly agree that the targets and revenue at risk for the last year of the STPIS for distribution can be used for the transitional year. There is also broad agreement that a parameter by parameter approach to setting targets for the transitional year for the STPIS for transmission can work.

The Demand Management and Embedded Generation Incentive Scheme<sup>543</sup> can also apply in some form for the transitional year. The Commission does not consider it necessary to provide for fall back arrangements in the transitional rules for this scheme as proposed by stakeholders.<sup>544</sup> Instead, the AER can stipulate the approach through the framework and approach paper.

The existing EBSS is unlikely to be able to operate. This is because the operating expenditure allowance is currently a key input into this scheme and this information will not be available until near the end of the period. However, the Commission notes that the AER intends to review the scheme in 2013. For this reason the possibility of an EBSS applying in the transitional year should not be ruled out. Further, even if the EBSS is to have no effect, it may need to apply for the year in some form for the continued smooth operation of the scheme (eg targets for the year may need to be set to actual expenditure).

The Commission maintains that capex sharing schemes and small scale incentive schemes should not operate in the transitional years for the 2014 group of NSPs. This decision is made on the basis that these schemes have not been applied before. These schemes can commence in the subsequent regulatory period (years 2-5).

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<sup>543</sup> This includes the NSW D-factor scheme.

<sup>544</sup> See for example, AER, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 11.

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<sup>246</sup> Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services

The new rules provide for the AER to review the efficiency of past capex and to make consequent adjustments to capex that would otherwise be rolled into the RAB. The Commission's view is that these adjustments should not apply in respect of capital expenditure that is incurred prior to or during the transitional year. This is because a NSP will not know what its capital expenditure allowance is for the transitional year until towards the end of the period and the capex incentive guidelines will not have been published prior to any year that precedes the transitional year.

Similarly, the AER will not be able to reduce the capex that would otherwise be rolled into the RAB, by virtue of it representing a non-arm's length margin or the capitalisation of opex, where that capex is incurred in a regulatory year that commences before the capex incentive guidelines have been published.

In relation to depreciation, for consistency the use of actual or forecast depreciation to calculate the opening value of the RAB for both the transitional and subsequent regulatory control periods will be as set out in the current regulatory determination. The AER will determine the method to be used to establish the opening RAB for the regulatory year following the subsequent regulatory control period, when it makes the subsequent regulatory determination. The AER should, however, set out the method it intends to use in the framework and approach paper.

#### **12.10.4 Matters to be dealt with in the framework and approach paper**

The framework and approach paper process precedes the normal regulatory determination process and, in this case, also precedes the placeholder determination process. Given the timing of this process, the framework and approach paper will be used to set out how the AER intends to deal with a number of matters for the transitional regulatory period, such as:

- how the incentive schemes will operate for this period (see section 12.10.3);
- the manner in which any true-up between the placeholder and full determination will be carried out for DNSPs that are subject to a price cap form of regulation; and
- the manner in which any true-up will be carried out for DNSPs providing alternative control services that are capable of being trued-up (eg public lighting and metering).

The NER do not limit the matters that can be covered in the framework and approach paper, so to the extent that it is relevant, given the content of the AER's rate of return guidelines, the framework and approach paper consultation process may also be used to identify:

- the manner in which any measurement period that may be required to calculate the return on debt or the return on equity will be identified; and

- the methodologies that the AER intends to employ when measuring the return on debt and the return on equity and how it considers those methodologies will contribute to the overall rate of return objective.

Because some of the guidelines that form the basis for the framework and approach paper may not be finalised until the end of November 2013, the framework and approach paper consultation process will be divided into two parts for the NSW DNSPs and ActewAGL:

- Part 1 will be finalised by 28 March 2013 and will cover matters that are not the subject of guidelines; and
- Part 2 will be developed after the new guidelines are being finalised and will set out the AER's proposed approach on the remaining matters specified in the rules and other matters relating to the transitional year. This part of the framework and approach paper will be finalised by 31 January 2014.

For TransGrid and Transend, the matters to be dealt with in the framework and approach paper are largely dependent on the AER's guidelines. Consultation on the framework and approach paper will therefore commence as each of the guidelines are finalised and will culminate in a finalised framework and approach paper by 31 January 2014.

The Commission is aware that an end date for the finalisation of the framework and approach paper of 31 January 2014 is two months later than what would normally occur under the framework and approach process. However, it is also cognisant of the fact that if some of the guidelines are not completed until 29 November 2013, then additional consultation may be required before the framework and approach paper is finalised. The transitional rules therefore require the AER to finalise the framework and approach papers for the 2014 group by 31 January 2014.

One important point that is worth bearing in mind in this context is that while the transitional rules specify the last date by which the framework and approach paper is to be published, they do not specify when consultation on the paper should commence. If it is assumed that it will not take the AER up to 29 November 2013 to finalise all of the guidelines, then consultation on certain elements of the framework and approach paper could commence as soon as the individual guidelines are published rather than waiting until all of the guidelines are finalised.

Staggering the consultation in this manner would provide more time to consult on each of the matters that the AER is required to deal with in the framework and approach paper. It will also provide NSPs with a good idea of the AER's intention on particular matters earlier than what would otherwise occur if the consultation period did not commence until 29 November 2013. The Commission therefore encourages the AER to commence consultation on particular matters as soon as the individual guidelines are published.

Finally, it is worth noting that the Commission is aware that some of the NSPs in the 2014 group are of the view that:

- they should be subject to the draft rather than the final guidelines; and
- the guidelines should set out how they are to be applied to particular NSPs in the transitional period.

On the first of these matters, the final guidelines will be developed in sufficient time for the NSPs to have recourse to them when preparing their regulatory proposals. The Commission therefore disagrees with the proposal for this group of NSPs to be subject to the draft rather than the final guidelines.

On the second matter, the Commission is of the opinion that these issues are better dealt with through the framework and approach paper rather than through the guidelines, which are not intended to apply in a NSP-specific manner. It does not therefore support this proposal.

#### 12.10.5 Treatment of ancillary issues for the transitional year

To minimise the number of decisions the AER will be required to make in the placeholder determination, the transitional rules provide for a number of decisions to be:

- carried over from the current regulatory determination, eg negotiating frameworks and negotiated transmission/ distribution service criteria;<sup>545546</sup> or
- carried over from the current regulatory determination, unless otherwise provided for in the framework and approach paper, eg classification of services and the form of control mechanism for standard control and alternative control services.<sup>547</sup>

The transitional rules relating to pass through events also provide for:

- those events identified in the current regulatory determination to be carried over; and

<sup>545</sup> For DNSPs the decisions that are to be carried over from the current regulatory determination include: the negotiating framework; the negotiated distribution service criteria; the procedures for assigning/reassigning retail customers in relation to tariff classes; the proposed pricing methodology for transmission standard control services; the application of Part J of Chapter 6A to services provided by dual function assets; and the manner in which the value of the opening regulatory asset base will be calculated at commencement of the next regulatory period (ie on the basis of forecast or actual depreciation).

<sup>546</sup> For TNSPs the decisions that are to be carried over from the current regulatory determination include: the negotiating framework; the negotiated transmission service criteria; and the pricing methodology.

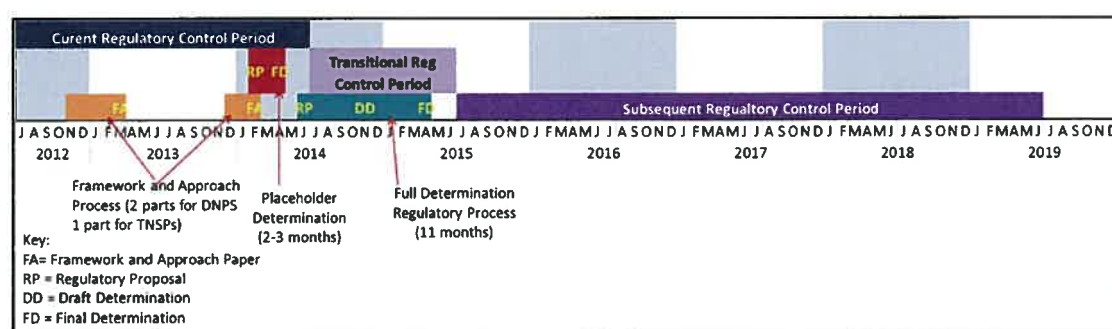
<sup>547</sup> For DNSPs the decisions that are to be carried over from the current regulatory determination, unless otherwise provided for in the framework and approach paper include: the classification of distribution services; the form of control mechanism for standard control services; and the form of control mechanism for alternative control services.

- the inclusion of the previously repealed “terrorism event”.<sup>548</sup>

### 12.10.6 Consistency of the transitional arrangements with principles

To summarise, the Commission has decided to delay the full regulatory determination process for the 2014 group of NSPs by 12 months and use the placeholder with true-up model to deal with the transitional year. The application of this model gives rise to two regulatory periods and two determination processes. The relationship between the various elements of this model and the timing of each element is depicted in Figure 2.

**Figure 12.2 2014 Group of NSPs Regulatory Determinations and Periods**



The Commission’s view on the consistency of these transitional arrangements with the principles set out in section 12.2 can be summarised as follows:

- *Principle 1: final rules to apply as soon as possible* - The inclusion of the true-up mechanism in the model means that, with the exception of the extended regulatory process provisions, the new rules and guidelines will apply in both the transitional year and the subsequent four years. The model therefore results in a faster transition to the new rules than the model specified in the consultation paper and will effectively result in the final rules substantially applying from 1 July 2014.
- *Principle 2: sufficient time for consultation* - The consultation period for the placeholder determination will be relatively short given the nature of the decisions to be made at the time, but sufficient time for stakeholder consultation will be made in the full determination process when the AER is actually assessing the revenue requirements by reference to the new rules. Delaying the

<sup>548</sup> In the current regulatory control period for NSPs, a terrorism event is a specified pass through event under the NER. However, in the *National Electricity Amendment (Cost pass through arrangements for network service providers) 2012 No. 4*, a “terrorism event” was removed from the list of specified pass through events in the NER that will apply to NSPs from their next regulatory control period on the basis that if a NSP wished to, it could nominate the terrorism event as an additional pass through event in its regulatory proposal. NSPs subject to these transitional arrangements will not be able to nominate additional pass through events for the transitional year so the transitional rule has been drafted such that, for the transitional year, the “terrorism event” is a specified pass through event under the NER.



full regulatory determination process by 12 months will also enable greater participation by interested parties in the guideline development process.

- *Principle 3: opportunity to recover at least efficient costs* - Because the new rules and guidelines will be effectively applied to both the transitional regulatory period and subsequent regulatory period, the application of these transitional arrangements will have no effect on a NSP's opportunity to recover at least the efficient costs they incur in the provision of regulated services over the five year period.
- *Principle 4: arrangements practicable having regard to resourcing constraints* - The true-up mechanism allows a more high level assessment to be undertaken in advance of the transitional year because it takes into account any difference between the placeholder value and the revenue requirement that would have been derived if the new rules had been applied. The adoption of this model should therefore go some way to alleviating the resourcing constraints that the AER, the 2014 group of NSPs and other stakeholders may otherwise face in 2013-14.
- *Principle 5: minimising price volatility* - The requirement for the AER to have regard to the "reasonably likely to minimise price variations" criterion when assessing a NSP's placeholder revenue proposal should ameliorate the potential for price shocks that may otherwise occur if a single year determination was made.

It follows from this assessment that, in the Commission's opinion, the transitional arrangements to be applied to the 2014 group of NSPs are consistent with the principles set out in section 12.2, and the NEO and RPP, more generally (see sections 2.4-2.6).

#### **12.10.7 Specific arrangements for ActewAGL**

Through discussions with the AEMC, ActewAGL has indicated that a 12 month delay to its electricity regulatory process would result in a direct overlap between its gas and electricity regulatory processes and, in so doing, give rise to "serious resourcing issues". ActewAGL has therefore requested that the submission date for its proposed revisions to the ACT, Queanbeyan and Palerang gas distribution network access arrangement be delayed by 12 months.

The Commission recognises that ActewAGL is relatively small and that requiring it to conduct its gas and electricity determination processes concurrently is likely to give rise to resourcing constraints. Such an outcome would obviously be at odds with the fourth principle in section 12.2 and, if not addressed, could compromise the regulatory process. The Commission has therefore decided to allow ActewAGL's gas access arrangement review submission date to be delayed by 12 months to 1 July 2015 and to enable the effect of any delays to be dealt with in accordance with rule 92(3), which states the following:

“...if there is an interval (the **interval of delay**) between a revision commencement date stated in a full access arrangement and the date on which revisions to the access arrangement actually commence:

- reference tariffs, as in force at the end of the previous access arrangement period, continue without variation for the interval of delay but;
- the operation of this subrule may be taken into account in fixing reference tariffs for the new access arrangement period.”

In its discussion with the AEMC, ActewAGL raised some concerns about the strength of the latter of these provisions and whether the AER would actually be compelled to undertake a true-up. The Commission accepts that the use of the word “may” in this provision appears to provide the AER with some discretion as to whether a true-up will be carried out. However, it must be borne in mind that when exercising discretion, the AER is required to have regard to both the NGO and the RPP. In the Commission’s opinion, these sections of the NGL would support the application of a true-up mechanism if the reference tariffs prevailing in the period of delay were lower (higher) than what they would otherwise have been.

It is worth noting in this context that the Commission’s view on this issue is consistent with the view expressed by the AER in its recent draft decision for the Victorian gas access arrangement review, as demonstrated by the following extract:<sup>549</sup>

“There will be a delay in the making of the final decision. The AER has therefore taken into account the operation of r. 92(3) of the NGR in fixing reference tariffs for the 2013–17 access arrangement period. The AER considers that the 2013 reference tariffs under the 2013-17 access arrangements should take effect from 1 July 2013 until 31 December 2013.

The AER considers that the interval of delay should not result in service providers incurring a windfall gain or loss, compared with what would have occurred if the 2013-17 access arrangements had taken effect from 1 January 2013. This approach is consistent with the efficiency objectives under the NGO and long term interest of gas consumers. This approach will also provide service providers with a reasonable opportunity to recover at least the efficient costs of providing reference services as approved in the access arrangements, consistent with the RPP.”

Given the manner in which the AER has indicated it will apply this provision, the Commission is satisfied that rule 92(3) can be relied upon to deal with the effect of any delay in ActewAGL’s gas access arrangement review process.

To give effect to the 12 month delay, the gas transitional rules will therefore:

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<sup>549</sup> AER, Access arrangement draft decision Envestra Ltd 2013-17 Part 1, September 2012, p277.

- allow the AER to extend the period for submitting an access arrangement revision proposal by up to 18 months under rule 52(3) of the NGR; and
- require the AER to exercise its power under the modified rule to extend ActewAGL's period for submission to 30 June 2015.

Finally, it is worth noting that while ActewAGL's revised access arrangement will be delayed by 12 months, the Commission expects that any true-up the AER carries out will result in the new NGR being effectively applied to the transitional year. The timing of the application of the new NGR to ActewAGL's gas distribution network should therefore be unchanged as a result of the 12 month delay.

## 12.11 Transitional arrangements to apply to 2015-2016 group of DNSPs

Energex, Ergon and SA Power Networks are currently required to submit their regulatory proposals to the AER by 31 May 2014 while CitiPower, Jemena, Powercor, SP AusNet (distribution) and United Energy are due to submit their proposals by 30 November 2014. Although the submission date for this group of NSPs is 6-12 months after the latest date by which the AER is required to finalise its guidelines, the 12 month delay to the 2014 group of NSPs' full determination process is expected to result in a material increase in the AER's workload over the period 31 May 2014 – 30 April 2015. Some insight into the workload the AER would face in this period if the 2015-2016 group were not subject to transitional arrangements can be found in the table below.

**Table 12.5 Regulatory determinations in 2014-2015 if 12 month delay to 2014 group of NSPs and no delay to 2015-2016 group of DNSPs**

NSP	Regulatory Determination Process
TransGrid and Transend	31 May 2014 - 30 April 2015*
ActewAGL, Ausgrid, Endeavour Energy and Essential Energy	31 May 2014 - 30 April 2015*
Directlink	31 May 2014 - 30 April 2015*
Ergon, Energex and SA Power Networks	31 May 2014 - 30 April 2015*
CitiPower, Jemena, Powercor, SP AusNet and United Energy	30 November 2014 - 31 October 2015*
NSW Gas access arrangement review	30 Jun 2014 – 31 May 2015

\* Note that the length of this process assumes that these NSPs would not be subject to the extended consultation process.

To minimise the resourcing constraints that may otherwise exist in this period, the Commission has decided to delay the commencement of the regulatory determination processes for the 2015-2016 group of DNSPs by five months<sup>550</sup> and require a 12 month, rather than a 15 month, regulatory determination process.

<sup>550</sup> A delay of this length will eliminate any overlap between the Victorian regulatory determination process and the 2014 group of NSPs and Directlink regulatory determination processes. It will also reduce the overlap between the Queensland regulatory determination process and the 2014 group of NSPs and Directlink regulatory determination processes by five months.

A delay of this length will not give the AER enough time to make a final determination before the commencement of the next regulatory periods (1 July 2015 or 1 January 2016, as the case may be). However, it will provide the AER with sufficient time to make a preliminary determination<sup>551</sup> (equivalent in practice to a draft determination) two months before the commencement of that regulatory period. The Commission has therefore decided to apply the preliminary determination with mandatory re-opener model to this group of DNSPs.

At its most elementary, this model involves:

- using the AER's draft determination as a placeholder for a NSP's revenue requirement and prices until the final determination is made; and
- using an adjustment mechanism to account for any difference between the draft and final determinations.

This model is referred to as the "preliminary determination with mandatory re-opener model" because, from a legal perspective, a binding (final) determination must be in place prior to the start of a regulatory period. The application of this model therefore requires:

- a final determination to be made in advance of the regulatory control period. In effect, what would have been the draft determination under a full determination process becomes the final determination. Because of its subsequent re-opening, this determination is referred in this chapter to the "preliminary determination";
- a mandatory re-opening of the preliminary determination and the substitution of this determination with a new determination by the AER ("substitute determination"). In effect, the new determination is the final determination that would have arisen through the usual determination process; and
- any differences between the preliminary and substitute determinations to be accounted for in the substitute determination through a NPV neutral adjustment.

It is the Commission's intention that the decision-making rules that would ordinarily apply to the making of a final determination will apply equally to the making of the substitute determination. It is also intended that consultation between the preliminary and substitute determinations be equivalent to the process set out in clauses 6.10.2-6.10.3 of the NER. DNSPs will therefore have an opportunity to submit a revised regulatory proposal and other stakeholders will also have an opportunity to make written submissions.

Before setting out how this model will work in practice, it is worth noting that it has a number of distinct advantages over the placeholder with true-up model, which the Commission considers warrant its application when there is sufficient time to do so:

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<sup>551</sup> This determination may be regarded as a 'preliminary determination' because it will be re-opened shortly thereafter.

<sup>254</sup> Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services

- First, the process to be followed and the decisions that the AER is required to make are in all practical respects equivalent to those it would have to make under a standard regulatory determination process. This includes the consultation process between the preliminary and final determination, which is intended to be the same as that between a standard draft and final determinations;
- Second, the true-up can be seen as analogous to that which is required between a final determination and the outcome of a merits review at the moment, so the concept of this type of true-up is familiar to stakeholders;
- Third, it provides a more robust basis for establishing this group's annual revenue requirements and prices than the placeholder determination process because the determination will be made in accordance with the new Chapter 6 rules rather than the high level criteria outlined in section 12.10.1;
- Fourth, it overcomes the measurement issues associated with the placeholder with true-up model because the AER's preliminary determination will be made before the commencement of the regulatory period; and
- Fifth, it will provide the DNSPs and other stakeholders with a greater degree of certainty about how the rate of return will be measured before the commencement of the regulatory period than is provided under the placeholder with true-up model.

The preliminary determination with mandatory re-opener model also has a number of advantages over clause 6.11.3(b). This clause states that if a period intervenes between the end of one regulatory control period and the commencement of a new determination, then the prior determination continues in force and appropriate adjustments can be made in the later determination. The advantages that the preliminary determination with mandatory re-opener model has over this clause are that it will:

- allow the new rules to come into effect earlier than clause 6.11.3(b);
- be more likely to result in prices in the first regulatory year that are closer to those established in the substitute determination than what would occur if prices were carried over from the prior determination;
- provide NSPs and other stakeholders with a greater degree of certainty about the rate of return that will apply over the regulatory period before the commencement of the period; and
- avoid a number of measurement issues and the need to have a regulatory determination applying for a partial year (ie 4.5 years).

The remainder of this section sets out how the Commission intends the preliminary determination with mandatory re-opener model to be applied to the 2015-2016 group of DNSPs, with particular emphasis placed on:

- the key stages of the preliminary and substitute determination process;
- the operation of incentive schemes;
- the time at which changes between the preliminary and substitute determinations will be taken into account; and
- other aspects of the transitional rules that will apply to this group of DNSPs.

#### **12.11.1 Stages of the preliminary and substitute determination process**

The preliminary determination with mandatory re-opener model consists of the following stages:

- the framework and approach stage;
- the regulatory submission and consultation stage;
- the preliminary determination stage, which is equivalent in practice to a draft determination;
- the consultation between preliminary and substitute determination stages, which is equivalent in practice to what occurs between a draft and final determination; and
- the substitute determination stage, which is equivalent in practice to a final determination.

Further detail on each of these stages is provided below.

##### **Framework and approach paper stage**

Under the new Chapter 6 rules, if there is an existing framework and approach paper in place and a DNSP has not requested the AER to make an amended or replacement framework and approach paper, the AER will only be required to amend or replace the paper if it concludes that it is necessary or desirable to do so. Although there is some optionality around this provision, the Commission would expect the AER to publish a new or amended framework and approach paper for this group of DNSPs, because it will need to deal with a number of new issues that were not required under the old framework and approach paper provisions. It may also need to use the framework and approach paper to set out the manner in which incentive schemes will operate in the first year of the regulatory process.

In accordance with the transitional rules, the framework and approach paper will need to be published six months before the 2015-2016 group of DNSPs submit their regulatory proposals.

### **Submission of regulatory proposals and initial consultation stage**

At the time the 2015-2016 group of DNSPs are due to submit regulatory proposals, there is still expected to be some workload congestion within the AER. It is not therefore possible to build in any additional consultation time in the lead up to the preliminary determination for the publication of an issues paper.

Although this group of DNSPs will not be subject to the extended regulatory process, they will still be required to submit an overview paper when lodging their regulatory proposals. They will also be subject to those rules that are intended to increase the level of customer engagement by NSPs when developing their regulatory proposal. In addition, the AER will be required to conduct a mandatory public forum on the regulatory proposals at the commencement of the process.

In accordance with the transitional rules, this group of DNSPs will be required to submit their regulatory proposals eight months before the commencement of the regulatory period.

### **Preliminary determination stage (equivalent in practice to a draft determination)**

The transitional rules, in conjunction with Chapter 6 of the NER, require the AER to publish the preliminary determination<sup>552</sup> two months prior to the commencement of the regulatory period. The process that the AER will follow to make the preliminary determination will in practice be identical to the process it would have followed to make a draft determination. This determination will have the status of the final determination until it is replaced by the substitute determination. DNSPs will therefore be required to have recourse to the determination when preparing their annual pricing proposals for the first year of the regulatory period.

When making the preliminary and substitute determinations, the AER will apply the same NEL and Chapter 6 provisions, and hence if faced with the same information it could be expected to make the same decision in both cases. In practice the revised regulatory proposal and the responses of stakeholders to the preliminary determination provides the AER with additional information that could mean its substitute determination differs from the preliminary determination.<sup>553</sup> It is possible therefore that the AER will have additional information when making the substitute determination as compared to the preliminary determination.

Notwithstanding this possibility, all stakeholders, including the AER and affected NSPs, have an interest in minimising the difference between the preliminary and substitute determinations to minimise the scale of any subsequent adjustment and

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<sup>552</sup> As noted in the introduction to this section, the application of the preliminary determination with mandatory re-opener model requires a binding determination to be made in advance of the regulatory control period. So what would have been the draft determination under a full determination process becomes a final determination. Because of its subsequent re-opening, this determination is referred to in this chapter as the "preliminary determination".

<sup>553</sup> Note that the transitional rules leave in place the same consultation provisions and requirement to provide a revised regulatory proposal as set out under the standard determination process set out in Chapter 6 of the NER.

price volatility. Minimising the extent of any difference can be helped by the AER, affected NSPs and other stakeholders:

- providing information to the AER as early as possible;
- engaging in as much consultation as possible and as early as possible in the regulatory determination process. The consultation requirements in the rules are only ever a minimum set of requirements and do not in any way restrict the degree of additional consultation that can be undertaken; and
- trying to establish areas of agreement amongst stakeholders on issues that might usually be left to later in the determination process

### **Consultation between the preliminary and substitute determination stages**

As soon as the preliminary determination is made, the AER will be required to publish an invitation for written submissions on the revocation and substitution of that determination. Although it is necessary to give practical effect to these transitional arrangements by requiring the AER to re-open the preliminary determination, in all other respects the arrangements are intended to be equivalent to those that would normally apply between a draft and final determinations. The consultation process is therefore intended to be equivalent to the process that would normally apply between the draft and final determination stages. NSPs will therefore be required to submit their revised regulatory proposals and any other submissions to the AER within a specified period of time and other stakeholders will also have the opportunity to make submissions on the preliminary determination.

Workload congestion within the AER is expected to diminish at the end of April 2015 when the AER publishes its final determinations for the 2014 group of NSPs. Provision will therefore be made for an extra month to be built into the regulatory process between the preliminary and substitute determinations to provide:

- NSPs an additional 15 business days to prepare their revised regulatory proposals and other stakeholders an additional 15 business days to make any submissions to the AER; and
- the AER an additional five business days to make its substitute determination.

It is worth noting in this context that the Commission has considered whether any additional time should be made for the cross submission stage and other elements of the extended regulatory process. However, it is of the opinion that it was more important to have the substitute determination in place soon after the commencement of the regulatory period, given that certain elements of the substitute determination will become operative as soon as the determination is made (see section 12.11.3).



### Substitute determination stage

The transitional rules require the AER to revoke the preliminary determination and replace it with the substitute determination<sup>554</sup> no later than four months into the first year of the regulatory period. In making this substitute determination, the AER will be required to have regard to the same matters that it is usually required by Chapter 6 to consider when making a final determination.

The AER will also be required to make provision for any adjustment that may be required to account for differences between the preliminary and substitute determinations, including, if appropriate, by allowing adjustments to be made to an existing or future approved pricing proposal. In accordance with the transitional rules, any adjustment that may be required is to be carried out on a NPV neutral basis.

To ensure that any adjustment that may be required does not result in price volatility over years 2-5, the requirement for a final year X factor anchor point (clause 6.5.9(b)(2) of the NEL) to be used when smoothing will be removed for the purposes of the transitional rules only (see section 12.10.2 for further detail).

Finally, it is worth noting that the substitute determination will be subject to merits review under the NEL as reviewable regulatory decision because it will:

- be a distribution determination within the meaning of the NEL. This is because it will be a determination of the AER under the rules that regulates either the prices a DNSP can charge for direct control services (standard control services and alternative control services) or the revenues the DNSP can earn from the provision of those services; and
- “set a regulatory period” as the AER will be required, as part of making the substitute determination, to make a decision under clause 6.12.1(2)(ii) on the commencement and length of the regulatory control period.

### Key dates

The key dates for the framework and approach paper, the submission of the regulatory proposal, the preliminary determination and the substitute determination for the 2015-2016 group of DNSPs are set out in the table below. As the information in this table reveals, the overall length of the regulatory determination process is 12 months.

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<sup>554</sup> As noted in the introduction to this section, the application of this model requires the mandatory re-opening of the preliminary determination and the substitution of this determination with a new determination made by the AER (“substitute determination”). In effect, the substitute determination is the final determination that would have arisen through the usual determination process.

**Table 12.6 Key Dates for 2015-2016 Group of DNSPs**

	Framework and Approach Paper Finalised	Regulatory Proposal Due	Preliminary Determination	Substitute Determination	Regulatory period*
Queensland and South Australian DNSPs	30 Apr 2014	31 Oct 2014	30 Apr 2015	31 Oct 2015	1 July 2015-30 June 2020
Victorian DNSPs	31 Oct 2014	30 Apr 2015	31 Oct 2015	30 Apr 2016	1 Jan 2016-31 Dec 2020

\* Note that, with the agreement of the AER, a regulatory period of no less than three years or more than five years could be adopted.

### 12.11.2 Operation of incentive schemes

As set out in section 12.10.3, the Commission is of the view that incentive schemes should, to the extent it is possible and appropriate, apply in each year of the regulatory period. In keeping with this approach, the Commission is of the view that:

- to the extent possible, the whole suite of incentive schemes should operate as normal during the 2015-2016 group of DNSPs next regulatory period; and
- the proposed application of the incentive schemes should be set out in the AER's framework and approach paper and, where relevant, the AER should have the flexibility to apply schemes differently in the first year.

In relation to the application of the new review of efficiency of past capex provisions, the AER will have the ability to preclude capex from being rolled into the RAB where it is inefficient, represents non-arm's length margins or inappropriate capitalisation of expenditure. The AER's ability to exercise this discretion will, however, be limited to regulatory years following the publication of the capex incentive guidelines as set out in sections 9.4 and 9.5.

In relation to depreciation, the AER will have discretion to decide whether actual or forecast capex will be used to establish the opening value of the RAB for the following regulatory period.

### 12.11.3 Accounting for differences between determinations

The preliminary determination will be made two months before the commencement of the 2015-2016 group of DNSPs' regulatory periods and will remain in place until the AER revokes and replaces it with the substitute determination. The remainder of this section sets out the Commission's views on the time at which changes between the preliminary and substitute determinations should be taken into account.

#### Changes in the prices of standard control services

Once the AER releases the preliminary determination, DNSPs will be required to prepare their annual pricing proposal for the first year of the regulatory period. To provide retailers and end-users with some certainty about the prices to be paid for

standard control services in the first year, the Commission expects the price of standard control services appearing in the approved pricing proposal to be maintained in that year.

Any adjustments that may be required to account for differences between the price of standard control services established in the preliminary and substitute determinations and the fact that this element of the preliminary determination will prevail throughout year 1, should therefore be carried out in years 2-5.

### **Changes in the price of alternative control services**

The alternative control services provided by the 2015-2016 group of DNSPs consist of a mixture of services that can be subject to a true-up adjustment (eg public lighting and metering services) and those that cannot (eg fee services and quoted services). The Commission's view on how changes in the price of alternative control services between the preliminary and substitute determinations should be dealt with can be summarised as follows:

- for those services that can be subject to a true-up adjustment, the Commission expects the prices appearing in the approved pricing proposal to be maintained for the duration of the first year and any true-up to be applied in years 2-5; and
- for those services that *cannot* be trued-up, the Commission is of the view that these prices should be revised as soon as the substitute determination is made.

A different approach can be applied to the latter types of alternative control services because there is no other avenue for the DNSPs to recoup (repay) the difference between the preliminary and substitute determinations. Allowing prices to be revised as soon as the substitute determination is made will therefore minimise the effect of any loss (gain) that may otherwise arise if the substitute determination allows higher (lower) prices.

### **Ancillary issues**

To the extent that there is any change in position by the AER between the preliminary determination and the substitute determination on matters that do not affect the price of standard control services, these should take effect as soon as the substitute determination is made. These elements include:

- pass through events;
- the negotiation framework;
- the negotiated distribution service criteria;
- the procedures for assigning/reassigning retail customers in relation to tariff classes;
- the proposed methodology for transmission standard control services; and

- the application of Part J of Chapter 6A to services provided by dual function assets.

#### 12.11.4 Length of the regulatory period

In addition to giving effect to the preliminary determination with re-opener model, the transitional rules also allow the 2015-2016 group of NSPs to propose, and permit the AER to approve, a regulatory period less than five years but not less than three years. This provision has been incorporated into the transitional rules to enable the NSPs and the AER to optimise the alignment of regulatory reviews across all NSPs (see section 12.10.2).

#### 12.11.5 Consistency of the transitional arrangements with principles

To summarise, the Commission has decided to delay the regulatory determination process for the 2015-2016 group of DNSPs by five months and to use the preliminary determination with mandatory re-opener model to deal with this delay. The Commission's view on the consistency of these transitional arrangements with the principles set out in section 12.2 can be summarised as follows:

- *Principle 1: final rules to apply as soon as possible* – Apart from the extended regulatory determination process, the new rules and guidelines will apply to this group of DNSPs from the commencement of the next regulatory period.
- *Principle 2: sufficient time for consultation* - The consultation period for the preliminary and substitute determinations is one month longer than the existing 11 month period and will therefore provide sufficient time for consultation.
- *Principle 3: opportunity to recover at least efficient costs* - The application of this transitional arrangement will have no adverse effect on the ability of the DNSPs to recover at least their efficient costs because the new rules and guidelines will apply over the entire period and any difference between the preliminary and substitute determinations will be accounted for through appropriate adjustments carried out on a NPV neutral basis.
- *Principle 4: arrangements practicable having regard to resourcing constraints* – A five month delay to the commencement of the 2015-2016 group of DNSPs' regulatory determination processes will ameliorate the workload congestion that would otherwise exist within the AER between 31 May 2014 and 30 April 2015 if the arrangements were not implemented. Although there will still be a degree of overlap during this period, the AER has informed the Commission that the proposed arrangements are workable.
- *Principle 5: minimising price volatility* – there is no a priori reason to expect that the application of this transitional arrangement will result in one-off price shocks. Indeed, the Commission considers this approach has the potential to minimise shocks to a greater extent than the placeholder with true-up model because the

preliminary determination is made by applying the same legal requirements as the substitute determination.

Overall, the Commission is of the opinion that the transitional arrangements to be applied to the 2015-2016 group of NSPs are consistent with the principles set out in section 12.2, and the NEO and the RPP, more generally (see sections 2.4-2.6).

## **12.12 Transitional arrangements to be applied to Directlink**

Directlink is currently due to submit its regulatory proposal to the AER by 31 May 2014 and its next regulatory period is due to commence on 1 July 2015.

Given the relatively small size of Directlink, the Commission has decided not to subject it to the same transitional arrangements that have been proposed for both the 2014 and 2015-2016 groups of NSPs. The new rules will therefore apply to Directlink from the commencement of the next regulatory period.

Although Directlink's regulatory determination process will not be delayed, the timing of its next regulatory period is such that transitional rules are required to:

- enable the final form of the AER's guidelines to be taken into account during the framework and approach paper process. To this end, the framework and approach paper will be required to be finalised by 31 January 2014 (see section 12.10.4); and
- reduce the length of the regulatory determination process from 15 months to 11 months. Although Directlink will not be subject to the extended regulatory determination process, it will still be required to submit an overview paper with its regulatory proposal and will be subject to the new rules that are intended to increase the level of customer engagement by NSPs when developing their regulatory proposals. The AER will also be required to conduct a mandatory public forum on Directlink's regulatory proposal.

## **12.13 Summary and timetable for next round of determinations**

The Commission's decision on the NSPs that should be subject to the transitional arrangements and the form that these arrangements should take can be summarised as follows:

- SP AusNet (transmission) will be subject to the old Chapter 6A rules for three years before transitioning to the new rules on 1 April 2017;
- ActewAGL, Ausgrid, Endeavour Energy, Essential Energy, TransGrid and Transend (the 2014 group of NSPs) will have their full regulatory determination processes delayed by 12 months and will be subject to the placeholder with true-up model. Given the limited time available, the regulatory determination process will be carried out over an 11 month period rather than a 15 month period;

- Energex, Ergon, SA Power Networks, CitiPower, Jemena, Powercor, SP AusNet and United Energy (the 2015-2016 group of DNSPs) will have their regulatory determination processes delayed by five months and will be subject to the preliminary determination with mandatory re-opener model. At the time these determinations processes are due to commence, there will still be some workload congestion for the AER. The regulatory determination processes will therefore be carried out over a 12 month period rather than a 15 month period;
- Directlink will not be subject to a delay in its regulatory determination process. However, because there is limited time available between the last date by which the AER's guidelines are to be finalised and its regulatory period, Directlink's regulatory determination process will be carried out over an 11 month period rather than a 15 month period; and
- Aurora, Powerlink, ElectraNet and Murraylink will be subject to the new rules, including the 15 month extended regulatory determination process, for their next regulatory periods.

To give effect to these arrangements, separate transitional rules have been developed for SP AusNet (transmission), the 2014 group of NSPs, the 2015-2016 group of DNSPs and Directlink. Transitional rules have also been developed to:

- require the AER to finalise all of the guidelines by 29 November 2013 and issue a statement by 21 December 2012 setting out its proposed schedule and the consultation procedure to be followed when preparing the guidelines; and
- specify when the AER's review of capex, for the purpose of identifying inefficient capex, non-arm's length margins and /or expenditure that is capitalised inappropriately, can commence.

These transitional rules are set out in Part ZW in Chapter 11.

The effect that these transitional rules will have on the regulatory determination process can be seen in Table 12.6, which sets out the timetable for the next round of regulatory determinations.

In addition to these electricity related transitional rules, a transitional rule has been included in the NGR to enable ActewAGL's proposed revisions to the ACT, Queanbeyan and Palerang gas distribution network access arrangement to be delayed by one year.

**Table 12.7 New timetable for regulatory determination processes**

NSP	Form of Transitional Arrangement	Next Regulatory Period		Framework and Approach		Regulatory Process		
		Length	Dates	Consultation Commences*	Paper Published	Regulatory Proposal Due	Draft Decision*	Final Decision
Transmission								
SP AusNet (Vic)	Next Determination	3 years	1 Apr 2014 -31 Mar 2017	n.a.	n.a.	28 Feb 2013	31 Aug 2013*	31 Jan 2014
	Subsequent Determination	5 years	1 Apr 2017-30 Mar 2022	30 Sep 2014 <sup>§</sup>	30 Apr 2015	31 Oct 2015	30 Jun 2016*	31Jan 2017
TransGrid, Transend (NSW and Tas)	Placeholder Determination	1 year	1 Jul 2014- 30 Jun 2015	n.a.	n.a.	31 Jan 2014	n.a.	31 Mar 2014
	Full Determination	4 years <sup>¶</sup>	1 Jul 2015- 30 Jun 2019	30 Nov 2013	31 Jan 2014	31 May 2014	30 Nov 2014*	30 Apr 2015
Directlink (Interconnector btw Qld and NSW)	New rules	9 years*	1 Jul 2015-30 Jun 2024	30 Nov 2013 <sup>§</sup>	31 Jan 2014	31 May 2014	30 Nov 2014*	30 Apr 2015
Powerlink (Qld)	No transitional arrangements <sup>§</sup>	5 years	1 Jul 2017- 30 Jun 2022	31 Dec 2014 <sup>§</sup>	31 Jul 2015	31 Jan 2016	30 Sep 2016*	30 Apr 2017
ElectraNet (SA)		5 years	1 Jul 2018- 30 Jun 2023	31 Dec 2015 <sup>§</sup>	31 Jul 2016	31 Jan 2017	30 Sep 2017*	30 Apr 2018
Murraylink (Interconnector btw Vic and SA)		10 years <sup>¶</sup>	1 Jul 2023- 30 Jun 2033	31 Dec 2020 <sup>§</sup>	31 Jul 2021	31 Jan 2022	30 Sep 2022*	30 Apr 2023
Distribution								
ActewAGL, Endeavour Energy, Ausgrid (ACT and NSW)	Placeholder Determination	1 year	1 Jul 2014-30 Jun 2015	n.a.	n.a.	31 Jan 2014	n.a.	30 Apr 2014
	Full Determination	4 years <sup>¶</sup>	1 Jul 2015-30 Jun 2019	Part 1: 31 Oct 2012 Part 2: 30 Nov 2013	Part 1: 31 Mar 2013 Part 2: 31 Jan 2014	31 May 2014	30 Nov 2014*	30 Apr 2015
Ergon, Energex and SA Power Networks (Qld and SA)	Preliminary Determination with mandatory re-opener	5 years <sup>¶</sup>	1 Jul 2015-30 Jun 2020	30 Sep 2013	30 Apr 2014	31 Oct 2014	30 Apr 2015 <sup>°</sup>	31 Oct 2015
Jemena, United Energy, CitiPower, Powercor and SP AusNet (Vic)	No transitional arrangements	5 years <sup>¶</sup>	1 Jan 2016-31 Dec 2020	31 Mar 2014	31 Oct 2014	30 Apr 2015	31 Oct 2015 <sup>°</sup>	30 Apr 2016
Aurora Energy (Tas)		5 years	1 Jul 2017- 30 Jun 2022	31 Dec 2014	31 Jul 2015	31 Jan 2016	30 Sep 2016*	30 Apr 2017

Notes: \* Indicative dates only because the dates for making a draft determination are not prescribed in the rules + Estimate only based on an assumption that Murraylink and Directlink seek to maintain the existing term of their regulatory periods. ° The transitional rules allow for a shorter regulatory period if the NSP proposes a shorter period and the AER approves the proposal. § Mandatory framework and approach stage because it is the first one for this NSP. ° These dates are fixed because the preliminary determination must be made two months before the commencement of the regulatory period. ¶ Key to elements of extended regulatory process: ^ Overview paper and mandatory public forum † All elements of extended regulatory process # Overview paper, mandatory public forum, additional time for NSP to submit revised regulatory proposal, and additional time for stakeholders to make submissions on draft determination and revised regulatory proposal.

## 13 Gas transitional arrangements

### Summary

- The only change in this final rule determination that affects the NGR is the amendment to the rate of return provisions.
- A key element of these provisions is the requirement for the relevant regulator to develop guidelines setting out the approach it intends to take when estimating a service provider's rate of return. The new rule will require these guidelines to be finalised by 29 November 2013.
- ATCO Gas' Mid-West and South-West Gas Distribution System and APA Group's Goldfields Gas Pipeline are the only pipelines affected by the timing of the implementation of the new framework.
- To ensure that the new rate of return framework can be applied to these two pipelines in the next round of access arrangement reviews, the transitional arrangements will permit:
  - the next Mid-West and South-West Gas Distribution System access arrangement revisions to be submitted by ATCO Gas up to three months after the ERA publishes the final rate of return guidelines; and
  - the next Goldfields Gas Pipeline access arrangement revisions to be submitted by APA Group up to six months after the ERA publishes the final rate of return guidelines.
- To the extent that the postponement of the proposed access arrangement revisions gives rise to a delay in the commencement of the revisions, the following will occur:
  - the reference tariffs in force at the end of the existing access arrangement will continue without variation; and
  - the ERA will be allowed to take into account the effect of any delay when setting reference tariffs in the new access arrangement period.

### 13.1 Introduction

The only change in this final rule determination that affects the NGR is the amendment to the rate of return provisions (see chapter 6). A key element of the new arrangements is the requirement for both the AER and the ERA to develop guidelines that set out the approach they intend to take to estimate the rate of return required by service providers (see section 6.5). Although the rate of return is determined as part of each access arrangement decision, the guidelines are an important part of the process and the Commission expects the guidelines to act as the starting point for each decision. In



accordance with the new rule, the AER and the ERA will be required to publish the final rate of return guidelines by 29 November 2013.

Based on the current timetable for access arrangement revisions, the only gas service providers that will be affected by the timing of the implementation of the new rate of return framework are:<sup>555</sup>

- ATCO Gas, which is due to submit its proposed revisions to the Mid-West and South-West Gas Distribution System access arrangement five months before the ERA is due to publish the final rate of return guidelines, on 1 July 2013; and
- APA Group, which is due to submit its proposed revisions to the Goldfields Gas Pipeline access arrangement one month after the ERA is due to publish the final rate of return guidelines, on 1 January 2014.

Given the overlap between the rate of return guideline development process and the access arrangement review process, the Commission has given further consideration to the transitional arrangements that could be put in place to:

- ensure that the new rate of return framework is applied to both ATCO Gas and APA Group during the next access arrangement review process;
- provide ATCO Gas and APA Group with sufficient opportunity to take into account the ERA's rate of return guidelines when developing their respective access arrangement revisions;
- ensure that ATCO Gas and APA Group have a reasonable opportunity to recover at least the efficient costs; and
- minimise the resourcing burden that the transitional arrangements and guideline development processes could otherwise place on the ERA and other stakeholders.

The remainder of this chapter is structured as follows:

- Section 13.2 provides further detail on the consultation process and the transitional arrangements that were proposed in the 14 September 2012 consultation paper;
- Section 13.3 summarises the submissions received in response to the consultation paper;
- Section 13.4 sets out the Commission's analysis of the alternative transitional arrangements that have been proposed for ATCO Gas and APA Group and its final determination on the form that these arrangements should take; and
- Section 13.5 provides guidance on the final rule.

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<sup>555</sup> All other gas service providers in eastern and Western Australia are due to submit revised access arrangements from mid-2014 onwards.

## **13.2 Consultation process**

On 14 September 2012, the AEMC published a consultation paper on the arrangements that could be applied to both gas and electricity service providers to facilitate the transition to the new rule and on 28 September 2012 conducted a stakeholder workshop. The consultation paper, amongst other things, set out:

- the principles that the Commission considered should guide the development of any transitional arrangements (see section 3.6); and
- the arrangements that could be put in place to facilitate the transition of ATCO Gas and APA Group to the new rate of return framework.

An overview of the transitional arrangements that were proposed in the consultation paper is provided below.

### **13.2.1 Transitional arrangements proposed for ATCO Gas**

ATCO Gas is currently due to submit its proposed revisions to the Mid-West and South-West Gas Distribution System access arrangement to the ERA on 1 July 2013, with the revisions to take effect from 1 July 2014. If the current timetable is maintained, ATCO Gas would submit its proposed access arrangement revisions five months before the ERA is required to publish its final rate of return guidelines (29 November 2013).

To enable the new rate of return framework to be applied to ATCO Gas in the next access arrangement period and to ensure that ATCO Gas would have an opportunity to take into account the final guidelines, the consultation paper proposed that ATCO Gas:

- prepare its proposed revisions to the Mid-West and South-West Gas Distribution System access arrangement on the basis of the draft rate of return guidelines;
- submit its proposed revisions one month after the scheduled review submission date (1 August 2013) so that it had time to take into account the ERA's draft rate of return guidelines before submitting its proposed revisions; and
- be given the opportunity to amend its proposed revisions if there was a material difference between the draft and final versions of the guidelines.

### **13.2.2 Transitional arrangements proposed for APA Group**

APA Group is currently due to submit its proposed revisions to the Goldfields Gas Pipeline access arrangement to the ERA on 1 January 2014, with the revisions to take effect from 1 January 2015. If the current timetable is maintained, APA Group would be required to submit its proposed access arrangement revision one month after the ERA is required by the new rule to publish its final rate of return guidelines.

To ensure that APA Group had sufficient time to take into account the final guidelines, the consultation paper proposed that APA Group:

- prepare its proposed revisions to the Goldfields Gas Pipeline access arrangement on the basis of the draft rate of return guidelines; and
- be given the opportunity to amend its proposed revisions if there was a material difference between the draft and final versions of the guidelines.

### 13.3 Submissions on consultation paper

Responses to this element of the consultation paper were received from the ERA, ATCO Gas and APA Group.

Overall, it appears that ATCO Gas and APA Group accept the premise upon which the transitional arrangements outlined in the consultation paper were based.<sup>556</sup> That is, they accept that some form of transitional arrangement is required to enable the new rate of provisions to be applied in their next access arrangement review process.<sup>557</sup> That said, they do have some concerns with the scope of the arrangements proposed in the consultation paper.

ATCO Gas' concerns primarily relate to:

- the requirement that it prepare its proposed access arrangement revisions on the basis of the draft rather than the final rate of return guidelines;<sup>558</sup> and
- the limited time it would have to take into account the draft guidelines before submitting its proposed access arrangement revisions and to subsequently amend its proposal once the final guidelines are published.<sup>559</sup>

Given its concerns with these elements of the proposal set out in the consultation paper, ATCO Gas proposes the use of an alternative arrangement that would involve:

- postponing the Mid-West and South-West Gas Distribution System review submission date to the later of 1 January 2014 and 3 months after the publication of the final rate of return guidelines;<sup>560</sup>

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<sup>556</sup> APA Group, Draft Rule Determination submission, 4 October 2012, pp. 3-4 and ATCO Gas, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 8.

<sup>557</sup> APA Group, Draft Rule Determination submission, 4 October 2012, pp. 3-4 and ATCO Gas, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 8.

<sup>558</sup> ATCO Gas, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 6.

<sup>559</sup> ATCO Gas, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, pp. 3-4.

<sup>560</sup> ATCO Gas, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 1.

- postponing the Goldfields Gas Pipeline review submission date by a further six months to minimise the effect of the delay in the Mid-West and South-West Gas Distribution System review process on the ERA's work program;<sup>561</sup> and
- accounting for the effect of any delay in the revisions commencement date specified in the Mid-West and South-West Gas Distribution System and Goldfields Gas Pipeline in accordance with rule 92(3) of the NGR, which ATCO Gas submits provides for:<sup>562</sup>
  - the reference tariffs prevailing at the end of the current access arrangement period to continue to operate; and
  - a NPV based true-up to occur when the access arrangement revisions come into effect.

In a similar manner to ATCO Gas, APA Group has some concerns with the proposal that it prepare the Goldfields Gas Pipeline access arrangement revisions on the basis of the draft, rather than the final rate of return guidelines. In APA Group's view, ATCO Gas and APA Group should have at least three months after the finalisation of the rate of return guidelines to submit their proposed access arrangement revisions.<sup>563</sup> APA Group is also of the view that:<sup>564</sup>

- any revisions required as a result of a trigger event (rule 51) should be subject to the same transitional arrangements; and
- any delay in the revisions commencement date arising as a result of the postponement of review submission dates should be dealt with through rule 92(3).

In contrast to the position taken by ATCO Gas and APA Group, the ERA is of the opinion that the transitional arrangements outlined in the consultation paper are unnecessary and could give rise to significant resourcing constraints within the ERA.<sup>565</sup> Specifically, the ERA is of the opinion that: <sup>566</sup>

- a one month delay to ATCO Gas' review submission date is unnecessary because the processes to develop the rate of return guidelines and to evaluate ATCO Gas' proposed access arrangement revisions are complementary, not sequential;

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<sup>561</sup> ATCO Gas, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 4.

<sup>562</sup> ATCO Gas, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 2.

<sup>563</sup> APA Group, Draft Rule Determination submission, 4 October 2012, p. 4.

<sup>564</sup> APA Group, Draft Rule Determination submission, 4 October 2012, p. 4.

<sup>565</sup> ERA WA, Consultation Paper on Savings and Transitional Arrangements submission, 18 October 2012, pp. 1-3.

<sup>566</sup> ERA WA, Consultation Paper on Savings and Transitional Arrangements submission, 18 October 2012, pp. 2-3.

- a transitional provision allowing amendments to be made to ATCO Gas' and APA Group's proposed access arrangements is also unnecessary because the ERA intends to publish the final guidelines before the ATCO Gas draft decision. The ERA submits that by publishing the final guidelines at this stage both service providers would have an opportunity to revise their proposed access arrangements; and
- any delay in the access arrangement review process could impose significant costs on the ERA and other stakeholders and place significant pressure on the ERA's constrained resources.

In subsequent discussions with the ERA about the ATCO Gas and APA Group proposal, the ERA maintained its view that the guideline and access arrangement review processes could be undertaken concurrently. The ERA noted, however, that if the review submission date for the Mid-West and South-West Gas Distribution System is to be deferred until three months after the release of the final rate of return guidelines, the transitional arrangements should:

- enable the review submission date for the Goldfields Gas Pipeline to be deferred by up to six months after the guidelines are finalised; and
- be sufficiently flexible to deal with:
  - any changes in the timing of the release of the final rate of return guidelines; and
  - the potential for ATCO Gas and APA Group to submit their proposed access arrangement revisions earlier, if they are in a position to do so.

The ERA also noted that any delay in the revisions commencement date arising as a result of the postponement of the review submission date could be accommodated through the operation of rule 92(3),<sup>567</sup> which allows for the effect of any delay on reference tariffs to be trued-up in the subsequent regulatory period.

Finally, it is worth noting that the Commission also received a submission from ActewAGL on the transitional arrangements that could be applied to its gas distribution network to accommodate the electricity transitional arrangements. This matter is dealt with in section 12.10.7.

## 13.4 Analysis

To enable the new rate of return framework to be applied in the next round of access arrangement reviews, transitional arrangements are required for ATCO Gas' Mid-West and South-West Gas Distribution System and APA Group's Goldfields Gas Pipeline. In the consultation paper published on 14 September 2012, the Commission set out one way in which the transitional arrangements could operate.

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<sup>567</sup> Further detail on rule 92(3) can be found in the following section.

This proposal did not receive any support from the ERA or the two service providers that would be the subject of the arrangements. In short, the ERA is of the view that transitional arrangements are unnecessary, while ATCO Gas and APA Group are of the opinion that the arrangements outlined in the consultation paper do not go far enough.

Given the diversity of positions taken on this issue, the Commission has given further consideration to:

- the necessity for any transitional arrangements; and
- the form that any transitional arrangements should take.

Further consideration has also been given to the development process for the rate of return guidelines.

The Commission's assessment of each of these issues is set out in the remainder of this section.

#### **13.4.1 Guideline development**

In the draft rule determination and draft rule the Commission set out a timetable for the development of the rate of return guidelines. The Commission has given further consideration to whether this level of prescription is required in the rule and is now of the opinion that:

- the NGR should simply require the first guidelines to be finalised by 29 November 2013; and
- the relevant regulator should have some flexibility to determine the dates on which key milestones will be achieved.

To ensure that service providers and other stakeholders have sufficient notice and certainty upfront, the ERA and the AER will be required by the transitional provisions to publish a statement by 21 December 2012 that sets out:

- the proposed schedule, including milestones and dates, for the rate of return guidelines; and
- the specific consultation procedure to be followed for the rate of return guidelines, which must be consistent with the rate of return consultative procedures.

#### **13.4.2 Need for transitional arrangements**

Under the new rate of return framework, the ERA will be required to develop guidelines that set out the methodologies that it intends to have regard to when determining the rate of return for service providers (see section 6.5).

As noted in section 6.5, the guidelines will not be binding. However, the Commission expects service providers, the ERA and the appeal body to have regard to them as a starting point for each access arrangement decision. If a service provider wishes to depart from the methodologies specified in the guidelines, then it must clearly set out in its access arrangement information the reasons for the proposed departure. The rate of return guidelines are therefore intended to play an integral role in the access arrangement review process.

Although the new rule will take effect on 29 November 2012, the guidelines are not required to be finalised until the end of November 2013. There will therefore be a gap between the date the new rule comes into effect and when the guidelines are in place.

The Commission disagrees with the position taken by the ERA that no transitional arrangements are required and notes that some form of the guidelines must be in place when ATCO Gas and APA Group are preparing their proposed access arrangement revisions. Whether or not it is the draft or final version of the guidelines is a separate question, which is considered in further detail in the following section. For current purposes, it is sufficient to note that the degree of overlap between the two processes means that without transitional arrangements:

- ATCO Gas is unlikely to have access to any form of the guidelines when preparing its proposed revisions; and
- APA Group would have less than a month to take into account the final guidelines when preparing its proposed revisions.

Given this overlap, the Commission remains of the view that transitional arrangements are required to ensure the new rate of return framework can be applied to ATCO Gas and the APA Group in the next access arrangement review process.

#### **13.4.3 Initial submission based on draft or final guidelines**

One of the issues raised in the ATCO Gas and APA Group submissions is whether the two service providers should be required to prepare their access arrangement revisions on the basis of either:

1. the draft rate of return guidelines and then have the opportunity to amend their respective proposed revisions once the guidelines are finalised; or
2. the final rate of return guidelines.

At the time the consultation paper was prepared, the first of these options was considered more appropriate because it minimised the potential for any delay in the revisions commencement date for the two pipelines in question. On reflection, the Commission accepts that, given the important role the rate of return guidelines are expected to play in an access arrangement review process, this option is not ideal. The Commission also recognises the potential for this option to result in:

- higher regulatory costs and delays to the review process, if there is a significant change in the ERA's position between the draft and final guidelines; and
- a greater burden being placed on the ERA, service providers and other stakeholders at a stage in the process where there is limited time available to the ERA to make its final decision.

The Commission has therefore given further consideration to the second option. On the one hand, this option is likely to result in lengthier delays to the commencement of revisions but on the other hand it will circumvent the need for:

- ATCO Gas and APA Group to amend their proposed access arrangement revisions once the guidelines are finalised; and
- any further consultation during the access arrangement review process.

Another benefit of this option is that it will provide the two service providers with greater certainty and clarity about how the ERA intends to apply the new rate of return framework, when preparing their respective proposals.

On balance, the Commission is of the view that the benefits of having the final guidelines in place before requiring revisions to be submitted to the ERA are likely to outweigh the effect of any delay in the commencement of the revised access arrangements. It follows that, in the Commission's view, the proposal to postpone the Mid-West and South-West Gas Distribution System and Goldfields Gas Pipeline access arrangement review processes is appropriate.

The implications that the Commission's position on this issue will have for the transitional arrangements to be applied to ATCO Gas' Mid-West and South-West Gas Distribution System and APA Group's Goldfields Gas Pipeline are considered in the following section.

#### **13.4.4 Form of the transitional arrangements**

To give effect to the position outlined above, the transitional provisions, in conjunction with the existing NGR, will need to specify:

- the time by which the proposed access arrangement revisions for the Mid-West and South-West Gas Distribution System and the Goldfields Gas Pipeline are to be submitted to the ERA;
- how any delays between the revision commencement date specified in the Mid-West and South-West Gas Distribution System and Goldfields Gas Pipeline access arrangements and the date the revisions actually take effect will be dealt with; and
- what will happen if a trigger event occurs before the ERA's guidelines are finalised.



These matters are considered, in turn, below.

### **Review submission dates**

To ensure that ATCO Gas and APA Group have sufficient time to take into account the final guidelines when preparing their proposed access arrangement revisions, the Commission has given further thought to the extension that may be required.

ATCO Gas and APA Group have both suggested that they should have at least three months between the release of the final guidelines and the date by which they will be required to submit their proposed access arrangement revisions.

To get an understanding of the effect that this type of delay would have on the ERA's resources, the AEMC has had further discussions with the ERA. The ERA has informed the AEMC that if a three month gap is applied to the Mid-West and South-West Gas Distribution System then, from a resourcing perspective, the Goldfields Gas Pipeline review should commence within six months of the release of the guideline.

The ERA has also suggested that, rather than defining a specific date for the revision submission date, the transitional provisions should state that the Mid-West South-West Gas Distribution System (Goldfields Gas Pipeline) revisions are to be submitted within three (six) months of the release of the final guidelines. The ERA has informed the AEMC that this type of reference point would enable the timing of the revision submission date to be varied if the guidelines were either early or late.

The Commission agrees with the ERA that there should be sufficient flexibility in the transitional arrangements to deal with:

- any changes in the timing of the release of the final rate of return guidelines; and
- the potential for ATCO Gas and APA Group to submit their proposed access arrangement revisions earlier, if they are in a position to do so.

The only outstanding issue that must be considered in this context is the length of time that ATCO Gas and APA Group will require to take into account the final form of the guidelines in their proposed access arrangement revisions.

The Commission does not have a definitive view on this issue because the time required will depend on, amongst other things, the materiality of the change in the ERA's position between the draft and final version of the guidelines and the overall complexity of the guidelines. The decision that follows should not therefore be construed as representing the Commission's general position on the length of time a service provider would need to submit their regulatory proposal following the finalisation of the guidelines.

For the purposes of these transitional arrangements, the Commission has had regard to the following matters when forming its view on the length of time that ATCO Gas and APA Group should have to submit their proposed access arrangement revisions:

- the suggestion made by both ATCO Gas and APA Group that there should be at least a three month gap between the finalisation of the ERA's guidelines and their respective review submission dates;
- the ERA's preference for the Mid-West and South-West Gas Distribution System and Goldfields Gas Pipeline access arrangement review processes to be staggered; and
- the ERA's suggestion that sufficient flexibility should be built into the transitional arrangements to allow ATCO Gas and APA Group to submit their proposed revisions earlier, if they are in a position to do so.

Taking all of these factors into account, the Commission is of the view that the transitional arrangements should permit:

- the next Mid-West and South-West Gas Distribution System access arrangement revisions to be submitted by ATCO Gas up to three months after the ERA publishes the final rate of return guidelines; and
- the next Goldfields Gas Pipeline access arrangement revisions to be submitted by APA Group up to six months after the ERA publishes the final rate of return guidelines.

It is worth noting in this context that the Commission's position on the Mid-West and South-West Gas Distribution System review submission date differs somewhat from ATCO Gas' proposal. Under ATCO Gas' proposal, it would be required to submit its revisions by the later of 1 January 2014 and three months after the publication of the guidelines.

The Commission understands that the reference point of 1 January 2014 was intended to provide ATCO Gas and other stakeholders with a degree of certainty about the earliest date by which revisions would need to be submitted.<sup>568</sup> In the Commission's view, sufficient clarity about the date by which the revisions are required to be submitted will be provided by:

- the new rule, which specifies the last date by which the guidelines are to be finalised (29 November 2013); and
- the statement that the ERA will be required to publish by 21 December 2012, which sets out its proposed schedule, including milestones and dates, for the rate of return guidelines.

The Commission does not therefore consider it necessary to incorporate the 1 January 2014 reference point in the transitional provisions.

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<sup>568</sup> ATCO Gas, Consultation Paper on Savings and Transitional Arrangements submission, 25 October 2012, p. 13.

Finally, it is worth noting that the Commission is cognisant of the constraints that the ERA faces and appreciates the flexibility it has shown in offering to accommodate any delay in the access arrangement review processes.

#### **Accounting for the effect of delays to the revision commencement date**

Postponing the Mid-West and South-West Gas Distribution System and Goldfields Gas Pipeline review submission dates is expected to result in a delay in the commencement of the access arrangement revisions for these two pipelines. Although not ideal, there are existing provisions within the NGR that set out what is to occur when there is a delay between the revision commencement date specified in an access arrangement and the date on which revisions actually commence. Specifically, rule 92(3) states that:

“...if there is an interval (the **interval of delay**) between a revision commencement date stated in a full access arrangement and the date on which revisions to the access arrangement actually commence:

- (a) reference tariffs, as in force at the end of the previous access arrangement period, continue without variation for the interval of delay; but
- (b) the operation of this subrule may be taken into account in fixing reference tariffs for the new access arrangement period.”

In the course of its discussions with the Commission about the effect of postponing the Mid-West and South-West Gas Distribution System and Goldfields Gas Pipeline review submission dates, the ERA has confirmed that rule 92(3) could accommodate any delay in the commencement of the revisions. The Commission also understands that the ERA has used this provision to deal with delays in the commencement date of both the 2010-2014 Mid-West and South-West Gas Distribution System access arrangement<sup>569</sup> and the 2011-2015 Dampier to Bunbury Natural Gas Pipeline access arrangement.<sup>570</sup> In both of these cases, the reference tariffs prevailing at the end of the previous access arrangement period continued for the duration of the delay and a NPV neutral true-up was carried out on a smoothed basis when the new reference tariffs were approved.<sup>571</sup>

Given the manner in which this provision has been utilised by the ERA, the Commission is satisfied that rule 92(3) can be relied upon to deal with the effect of any delay between:

- the revision commencement date specified in the Mid-West and South-West Gas Distribution System and Goldfields Gas Pipeline access arrangements; and

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<sup>569</sup> ERA, Final Decision on WA Gas Networks Pty Ltd proposed revised access arrangement for the Mid-West and South-West Gas Distribution Systems, 28 February 2011, para 764.

<sup>570</sup> ERA, Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, 31 October 2011, para 797.

<sup>571</sup> See for example, para 764 of ERA, Final Decision on WA Gas Networks Pty Ltd proposed revised access arrangement for the Mid-West and South-West Gas Distribution Systems, 28 February 2011.

- the date that the revisions actually take effect for these two pipelines.

No additional transitional provisions are therefore required to deal with this type of delay.

One final point that is worth noting in this context, is that during its discussions with the Commission, the ERA noted the potential for a delay in the commencement date of the Mid-West and South-West Gas Distribution System access arrangement to give rise to bridging finance related costs. The Commission is aware that this was an issue in the last access arrangement review process<sup>572</sup> and recognises the potential for it to recur if there is a significant delay in the revisions commencement date. However, the Commission is of the view that the ERA is best placed to deal with this issue when assessing ATCO Gas' proposed access arrangement provisions. No provision has therefore been made within the transitional provisions to deal with this issue.

### Effect of trigger mechanisms

The final matter that the Commission has considered is whether transitional arrangements may be required to deal with trigger events that would otherwise require the submission of revisions before the rate of return guidelines are finalised.<sup>573</sup>

At the outset it is worth noting that the Commission recognises the important role that trigger events can play in an access arrangement. That said, it is possible that if these mechanisms are triggered before the ERA finalises the guidelines they could undermine the transitional arrangements outlined above. To ensure that this does not occur, the Commission is of the opinion that any revisions required as a result of the operation of a trigger event should be delayed in the same manner as that set out in section 13.4.3.

One problem with expanding the application of the transitional arrangements to trigger events is that the delay would not be captured by rule 92(3) because this rule only applies to delays between:

- the revision commencement date specified in an access arrangement; and
- the date that the revisions actually take effect.

Given the potential for a trigger event to result in revisions commencing before the commencement date specified in an access arrangement, rule 92(3) cannot, in its current form, be relied upon to deal with delays of this nature. An additional transitional provision is therefore required to address this gap. The precise form that this provision takes is outlined in section 13.5.1, but in short it will expand the definition of the term 'interval of delay' to include delays of this nature.

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<sup>572</sup> *Application by WA Gas Networks Pty Ltd (No. 3)* [2012] ACompT 12, paras 204-221.

<sup>573</sup> The effect that a trigger mechanism may have on the review submission date specified in an access arrangement is set out in rule 51(1) of the NGR. In accordance with this rule, the review submission date specified in an access arrangement may advance to an earlier date if the arrangement includes a trigger mechanism and the trigger event occurs.

Finally, it is worth noting that the trigger event issue is unique to the Goldfields Gas Pipeline because the Mid-West and South-West Gas Distribution System access arrangement does not have a defined trigger event. This element of the transitional provisions therefore only applies to the Goldfields Gas Pipeline.

### Summary

To summarise, under the revised transitional arrangements outlined above, the following will occur:

- ATCO Gas will be permitted to submit the Mid-West and South-West Gas Distribution System access arrangement revision proposal to the ERA up to three months after the ERA finalises the rate of return guidelines;
- APA Group will be permitted to submit the Goldfields Gas Pipeline access arrangement revisions proposal to the ERA up to six months after the ERA finalises the rate of return guidelines. The requirement to submit within this period extends to any revisions required as a result of the operation of a trigger mechanism in the current access arrangement; and
- delays in the commencement of revisions will either be dealt with under rule 92(3) or the transitional provision pertaining to trigger event related delays.

#### 13.4.5 Overall assessment of the revised transitional arrangements

To assess the overall consistency of the revised transitional arrangements with the NGO and the RPP, the Commission has had regard to the principles set out in section 3.6. The Commission's findings can be summarised as follows:

- *Principle 1: final rules to apply as soon as possible* - The revised arrangements will enable the new rule to be applied to both ATCO Gas and APA Group during the next access arrangement review process. The revised arrangements may therefore be viewed as being consistent with this principle.
- *Principle 2: sufficient time for consultation* - The revised arrangements will have no effect on the level of stakeholder consultation already provided for in the access arrangement review process. They will, however, enable greater participation by interested parties in the rate of return guideline development process. The revised arrangements may therefore be viewed as being consistent with this principle.
- *Principle 3: opportunity to recover at least efficient costs* - The revised arrangements will have no effect on the opportunity that ATCO Gas or APA Group will have to recover at least efficient costs. The revised arrangements may therefore be viewed as being consistent with this principle.
- *Principle 4: arrangements practicable having regard to stakeholders' resourcing constraints* - The revised arrangements may place some additional resourcing pressure on the ERA in early 2015 because there will be an overlap between the

Mid-West and South-West Gas Distribution System and Goldfields Gas Pipeline access arrangement review processes. However, the ERA has informed the Commission that the proposed arrangements are workable.

- *Principle 5: minimising price volatility* - The revised arrangements will have no obvious effect on price volatility because if there is any delay in the commencement of revisions:
  - the existing reference tariffs will continue to operate; and
  - any true-up that may be required should be carried out in NPV neutral terms and smoothed over the remaining term of the new access arrangement period.

It follows from this assessment that, in the Commission's opinion, the revised arrangements are consistent with the principles set out in section 3.6, and the NGO and RPP, more generally.

### 13.5 Guidance

To give effect to the transitional arrangements outlined in the preceding section, the transitional provisions provide for:

- the AER and the ERA to publish final rate of return guidelines by 29 November 2013 and to issue a statement by 21 December 2012 setting out:
  - the proposed schedule, including milestones and dates, for the rate of return guidelines; and
  - the specific consultation procedure to be followed for the rate of return guidelines, which must be consistent with the rate of return consultative procedures.
- the postponement of the Mid-West and South-West Gas Distribution System and Goldfields Gas Pipeline review submission dates; and
- the application of rule 92(3), in cases where there is a delay between the date that trigger event related revisions should have taken effect and the date the revisions actually come into effect.

Further detail on the transitional provisions that have been put in place to give effect to the latter two of these matters is set out below.

#### 13.5.1 Postponement of review submission dates

In its current form, rule 52 states that a service provider must, on or before the revision submission date, submit an access arrangement revision to the regulator. The period for submitting an access arrangement may be extended under rule 52(3), but this rule only provides for a two month extension. To enable the Mid-West and South-West Gas

Distribution System and Goldfields Gas Pipeline review submission dates to be delayed for the required period, the transitional provisions:

- modify rule 52(3) to allow the ERA to extend the period for submitting an access arrangement revision proposal by up to 18 months;<sup>574</sup> and
- require the ERA to exercise its power under the modified rule to extend the Mid-West and South-West Gas Distribution System (Goldfields Gas Pipeline) period for submission to a date that is no later than three (six) months after the rate of final return guidelines are published.

### 13.5.2 Delays to trigger event related revisions

Rule 92(3) currently states that if there is a delay between the revisions commencement date specified in an access arrangement and the date the revisions actually take effect:

- the reference tariffs prevailing at the end of the previous access arrangement period will continue without variation for the interval of delay; and
- the delay may be taken into account when fixing reference tariffs for the new access arrangement period.

The definition of 'interval of delay' in rule 92(3) does not currently capture delays between the date revisions should have taken effect as a result of the operation of the trigger mechanism and the date the revisions actually come into effect. A transitional provision is therefore required to overcome this gap.

To ensure that rule 92(3) can be applied if a trigger event under the Goldfields Gas Pipeline access arrangement causes the revision submission date to advance, the transitional provisions will define the term 'interval of delay', for the purposes of rule 92(3), as:

“the period between the date that is 12 months after the date that the review *submission date* advances to, by virtue of the operation of rule 51(1) and that access arrangement, and the date on which revisions to the access arrangement actually commence.”

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<sup>574</sup> An 18 month period has been referred to in this transitional rule to accommodate the trigger event provisions specified in the Goldfields Gas Pipeline access arrangement, which could occur at any time in the lead up to the review submission date specified in this access arrangement.

## Abbreviations

ACT	Australian Competition Tribunal
AEMC or Commission	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APIA	Australian Pipeline Industry Association
ARR	annual revenue requirement
ATA	Alternative Technology Association
Brattle	The Brattle Group
capex	capital expenditure
CAPM	Capital Asset Pricing Model
CPA	Competition Principles Agreement
DBP	Dampier Bunbury Pipeline
DNSP	distribution network service provider
DRP	debt risk premium
EBSS	efficiency benefit sharing scheme
ENA	Energy Networks Association
ERA	Economic Regulator Authority
ESAA	Energy Supply Association of Australia
ESCV	Essential Services Commission of Victoria
ETNOF	Electricity Transmission Network Owners Forum
EUAA	Energy Users Association of Australia
EURCC	Energy Users Rule Change Committee
FIG	Financial Investor Group



IPART	Independent Pricing and Regulatory Tribunal
LMR	Limited Merits Review
MAR	maximum allowed revenue
MCE	Ministerial Council on Energy
MEU	Major Energy Users
NBN	National Broadband Network
NEL	National Electricity Law
NEM	National Electricity Market
NEO	national electricity objective
NER	National Electricity Rules
NGL	National Gas Law
NGO	national gas objective
NGR	National Gas Rules
NPV	net present value
NSP	network service provider
NSW T-Corp	NSW Treasury Corporation
OEB	Ontario Energy Board
opex	operating expenditure
PTRM	post-tax revenue model
QTC	Queensland Treasury Corporation
RAB	regulatory asset base
RIIO	Revenue = Incentives + Innovation + Outputs
RIN	Regulatory Information Notice
RIPUC	Rhode Island Public Utilities Commission
RIT-D	Regulatory Investment Test for Distribution

RIT-T	Regulatory Investment Test for Transmission
RPP	Revenue and Pricing Principles
SCER	Standing Council on Energy and Resources
SCO	Standing Committee of Officials
SFG	Strategic Finance Group Consulting
SORI	Statement of Regulatory Intent
STPIS	service target performance incentive scheme
TNSP	transmission network service provider
UE and MG	United Energy and MultiNet Gas
Victorian DPI	Victorian Department of Primary Industries
WACC	Weighted Average Cost of Capital

## A Detailed examples of potential capex sharing schemes

This appendix includes a non-exhaustive list of possible ways in which the AER might design a capex sharing scheme under the draft rules.<sup>575</sup>

Figure A.1 below presents two different models: Model 1 presents a stylised example similar to that provided by the ENA's consultants of a capex efficiency carry-over scheme with a five year carry-over period using a WACC of 7.5%; Model 2 presents a stylised example of the ex-ante or fixed incentive rate scheme previously used by Ofgem.

**Figure A.1 Examples of efficiency carryover scheme and ex ante incentive rate scheme with periodic true-up**

<b>Model 1: EBC "capex efficiency carry over" scheme</b>										
Year	1	2	3	4	5	6	7	8	9	10
Forecast capex	300	330	270	300	330					
Actual capex	280	310	300	290	320					
Underspend	20	20	-30	10	10					
Annual financing benefit	1.50	1.50	-2.25	0.75	0.75					
Year 1 benefit	1.50	1.50	1.50	1.50	1.50					
Year 2 benefit		1.50	1.50	1.50	1.50	1.50				
Year 3 benefit			-2.25	-2.25	-2.25	-2.25	-2.25			
Year 4 benefit				0.75	0.75	0.75	0.75	0.75		
Year 5 benefit					0.75	0.75	0.75	0.75	0.75	
Benefit / Carry over	1.50	3.00	0.75	1.50	2.25	0.75	-0.75	1.50	0.75	0.00
Discount factor (to end of year 5)	1.28	1.29	1.20	1.11	1.04	0.98	0.90	0.83	0.78	0.72
Total benefits (PV at end year 5)	39.02									
DB benefits (PV at end year 5)	12.73									
Incentive rate	32.62%									
<b>Model 2: Ex-ante incentive rate with true-up at start of regulatory period</b>										
Annual underspend	20	20	-30	10	10					
Total Benefits (PV at end year 5)	39.02									
Target share of underspend (PV at end year 5)	12.73									
Benefit already received	20	40	10	20	30					
Cumulative underspend	1.5	3	0.75	1.5	2.25					
Financing benefit from underspending	10.84									
Total benefit already received (PV at end year 5)	1.88									
Additional benefit required (PV at end year 5)	32.62%									

In the Model 1 scheme, the business has a total underspend across the five years of \$30 million in nominal terms. This has a present value of \$39 million at the end of year 5. In keeping with earlier Australian schemes the benefit to the business is taken to be the financing cost forgone from having underspent the capex allowance contained in the allowed revenue requirement. This has a present value of \$12.7 million (at the end of year 5) leading to the business retaining 32.6 per cent of the available benefit.

The Model 2 scheme is designed to achieve the same incentive rate as that obtained from Model 1, namely 32.6 per cent, for illustrative purposes. Again, the NSP obtains a financing benefit from having underspent its capex allowance although in this case that only goes through to the end of the current regulatory period. Again the present value of the underspend is \$39 million (at the end of year 5) and the NSP receives a financing benefit of \$10.8 million through to the end of the regulatory period. To achieve the specified incentive rate of 32.6 per cent the NSP requires total benefits of \$12.7 million in present value terms (at the end of year 5) meaning an additional benefit of \$1.9 million will have to be given to the NSP in the form of additional allowed revenue requirement at the start of the next regulatory period.

<sup>575</sup> These examples have been developed with advice from Economic Insights.

Figure A.2 provides a stylised example of how a scheme involving an annual true up of efficiency gains and losses (as Ofgem plans to use) might work (Model 3).

**Figure A.2 Example of ex ante incentive rate scheme with lagged annual true-up**

Model 3: Ex-ante incentive rate with annual lagged true-up	1	2	3	4	5	6	7	8	9	10
Year										
Forecast capex	300	330	270	300	330					
Actual capex	280	310	300	290	320					
Underspend	20	20	-30	10	10					
Year 1 effect										
Underspend	20									
Total Benefits (PV at end year 2)	22.29									
DE's target share of benefit	7.27									
Benefit already received										
Financing benefit from underspending	1.50									
Benefit already received (PV at end year 2)	1.57									
Additional benefit required (PV at end year 2)	5.60									
Year 2 effect										
Underspend		20								
Total Benefits (PV at end year 3)		22.29								
DE's target share of benefit		7.27								
Benefit already received										
Financing benefit from underspending		1.50								
Benefit already received (PV at end year 3)		1.57								
Additional benefit required (PV at end year 3)		5.60								
Year 3 effect										
Underspend			-30							
Total Benefits (PV at end year 4)			-33.44							
DE's target share of benefit			-10.91							
Benefit already received										
Financing benefit from underspending			-2.25							
Benefit already received (PV at end year 4)			-2.51							
Additional benefit required (PV at end year 4)			-8.40							
Year 4 effect										
Underspend				10						
Total Benefits (PV at end year 5)				11.15						
DE's target share of benefit				3.84						
Benefit already received										
Financing benefit from underspending				0.75						
Benefit already received (PV at end year 5)				0.84						
Additional benefit required (PV at end year 5)				2.80						
Year 5 effect										
Underspend					10					
Total Benefits (PV at end year 6)					11.15					
DE's target share of benefit					3.84					
Benefit already received										
Financing benefit from underspending					0.75					
Benefit already received (PV at end year 6)					0.84					
Additional benefit required (PV at end year 6)					2.80					
Summary										
Financing benefits (nominal)			1.57	1.57	-2.51	0.84	0.84			
Financing benefits (PV at end year 5)			2.08	1.93	-2.70	0.84	0.78			
Total financing benefits (PV at end year 5)						2.83				
Additional benefits required (nominal)			5.60	5.60	-8.40	2.80	2.80			
Additional benefits required (PV at end year 5)			8.06	8.47	-8.03	2.80	2.60			
Total additional benefits required (PV at end year 5)						6.60				
Total DE benefits (PV at end year 5)						12.73				
Realised incentive rate						32.82%				

Again the same data as used in Models 1 and 2 are used and the same ex-ante incentive rate of 32.6 per cent is chosen for illustrative purposes. The underspend from year 1 is now true-up at the start of year 3 and so on leading to the year 5 underspend being true-up at the start of year 7. The NSP now effectively only retains one year of financing benefits on a rolling basis through the regulatory period. In Model 3 the year 1 true-up is done at the start of year 3 in present value terms at the end of year 2, the year 2 true-up is done at the start of year 4 in present value terms at the end of year 3 and so on.

Converting the smaller financing benefits to present values terms at the end of year 5 for comparison with Model 2, the NSP has retained benefits of \$2.9 million out to year 7. Converting the larger additional benefits required series to present value terms at the end of year 5, the NSP requires additional revenue of \$9.8 million (delivered in a

series of annual revenue requirement additions in years 3 through to 7) to achieve the specified ex-ante incentive rate.

The main difference between Models 2 and 3 is that the periodic true-up in Model 2 allows the financing benefit to make up most of the NSP's overall benefit whereas the lagged annual true-up in Model 3 requires most of the NSP benefit to come from additional allowances.

## B Sample of contingent projects and indicative costs

Below are samples of transmission contingent projects and their anticipated values which were accepted by the AER in recent transmission regulatory determinations. These were considered as part of the Commission's analysis on establishing an appropriate threshold for distribution and transmission contingent projects.

**Table B.1 Contingent projects and indicative costs**

TNSP	Regulatory period	Project	Cost	Unit	Triggered
Powerlink	2012/13 to 2016/17	Galilee Basin connection shared network works	88.4	\$m, 2011-12	No
		Moranbah area	54.9		No
		Bowen industrial estate	80.7		No
		Callide to Moura transmission line and Calvale transformer	50.8		No
		Gladstone state development area	115.7		No
		Ebenezer establishment	62.7		No
		QNI upgrade	60.6		No
		Western Downs to Columboola 275kV 3rd circuit	59.5		No
		Columboola to Wandoan South 275kV 3rd circuit	63.3		No
		Halys to Blackwall 500kV operating at 275kV,	148.9		No
		Halys to Western Downs, 3rd and 4th circuits, 500kV operating at 275kV	261.4		No
		Halys to Greenbank, 3rd and 4th circuits, 500kV operating at 275kV	149.2		No
Transend	2009/10 to 2013/14	Sheffield–George Town new transmission line	70	\$m, 2007-08	No
		Burnie–Smithton new transmission line	88		No
		Sheffield–Farrell new transmission line	79		No

TNSP	Regulatory period	Project	Cost	Unit	Triggered
		Sheffield–Burnie new transmission line	52		No
		St Helens new 110/22 kV connection site	46		No
		Palmerston– Sheffield 220 kV transmission line augmentation	22		No
		Waddamana–Lindisfarne 220 kV transmission line second circuit	22		No
		Trevallyn Substation new 220/110 kV injection point	21		No
		Queenstown Substation security upgrade	11		No
TransGrid	2009/10 to 2013/14	Kemps Creek–Liverpool 330 kV line—undergrounding of all or part of the proposed connection	108	\$m, 2007-08	No
		Hunter Valley–Central Coast 500 kV line	300		No
		Darlington–Balranald system upgrade 275 kV	51		No
		Yass to Wagga 500 kV double circuit transmission line	329		No
		Liddell–Tamworth 330 kV	163		No
		Tamworth–Armidale 330 kV line	130		No
		Bannaby–Yass reinforcement	45		No
		Williamsdale–Cooma 3rd circuit	40		No
		New 500/330 kV substation at Richmond Vale	80		No
		CBD and inner metropolitan area supply	342		No
		Gadara/Tumut load area support	54		No
		Orange 330/132 kV substation	47		No
		Victorian interconnector development	35		No

TNSP	Regulatory period	Project	Cost	Unit	Triggered
		QNI upgrade—line series compensation project	60		No
		Reactive support at seven sites	36		No
ElectraNet	2008/09 to 2012/13	Eyre Peninsula reinforcement	150	\$m	No
		Riverland reinforcement	130		No
		Yorke Peninsula reinforcement	41		No
		South East reinforcement	33		No
		Bungama reinforcement	12		No
		Southern Suburbs reinforcement	16		No
		Playford (Davenport) to Leigh Creek 132 kV transmission line	11 <sup>576</sup>		
		Fleurieu Peninsula reinforcement	65		No
		Murray Mallee reinforcement	34		No
		Munno Para reinforcement	26		Approved \$39.3 (\$m, 2007/08) on 11 March 2011
		Lucindale West reinforcement	17		No
		Western Suburbs reinforcement	15		No
		Tailem Bend to Tungkillo reinforcement	41		No
		Parafield Gardens West	14		No
		Para – Brinkworth – Davenport 275 kV transmission lines	12		No
		Heywood interconnection capacity upgrade	80		No
		Northern transmission reinforcement	75		No

<sup>576</sup> Five per cent of the MAR is \$11m, which makes this amount the cost threshold for ElectraNet's contingent projects.



TNSP	Regulatory period	Project	Cost	Unit	Triggered
		Adelaide CBD line works component	105		Approved \$131.38 (\$m, nominal) on 1 November 2009
		Transformer ballistic proofing	17		No

Source: AER final decision, ElectraNet transmission determination 2008-09 to 2012-13, 11 April 2008, p. 61; AER final decision, Powerlink transmission determination 2012-13 to 2016-17, April 2012, p. 45; AER final decision, Transend transmission determination 2009-10 to 2013-14, 28 April 2009, pp. 55-57; AER final decision, TransGrid transmission determination 2009-10 to 2013-14, 28 April 2009, p. 43.