Chapter 3: Revenue building blocks for Standard Control Services

Introduction

The NER details the various decisions the AER has to make in order to determine the revenue we require to recover the costs of providing Standard Control Services.

To assist the AER in making the decisions we have provided them with our ‘building block’ proposal. It includes all the information necessary for the AER to determine the relevant allowance for capital returns, depreciation, operating expenditure and the cost of income tax, as well as other inputs required to allow calculation of the Annual Revenue Requirement.

Customer benefits

Our building block proposal is in line with our service commitment to regional Queensland, and our commitment to deliver for the best possible price.

Changes to the way we plan and operate our network, as well as the efficiencies and effectiveness we have been able to achieve as an organisation over recent years, place us in a strong position to minimise our revenue requirement as we move into the next period.

Our customers appreciate the best possible price is not the lowest possible price. We are seeking sustainable outcomes, which address affordability concerns now without sacrificing service or affordability in the future.

3. Revenue building blocks for Standard Control Services

3.1 Background

The approach the AER must take in determining the revenue requirements for Standard Control Services is detailed in Part C of Chapter 6 of the NER.

To assist the AER undertake the task, Ergon Energy is required to develop a building block proposal, which encompasses five broad components:

- return on capital
- return of capital (depreciation)
- operating expenditure
- tax allowance
- revenue increments/decrements.

These building blocks, added together, allow the AER to determine the Annual Revenue Requirement (ARR) for each regulatory year.[28]

Ergon Energy's building block proposal contains the necessary information to allow the AER to make relevant decisions in accordance with the NER requirements. We have also populated the AER's Post Tax Revenue Model (PTRM) with the necessary information that allows the AER to determine the ARR, including the revenue increments and decrements set out in clause 6.4.3 of the NER.[29]

Ergon Energy has used a version of the PTRM developed by the AER in May 2014 that accounts for the changes resulting from the AER's Rate of Return Guideline. We have also populated the current version of the PTRM as issued by the AER in June 2008. Both PTRMs accompany our Regulatory Proposal.[30] Taken together, these two PTRMs allow Ergon Energy to comply with clause 6.3.1(c)(1) of the NER.

This chapter summarises our approach to addressing each of the building block components, including the values we have derived for each component. It also includes information on the X-factors applied to building block revenues, as well as the application of the 2015-20 incentive schemes.

A graphical depiction of the building block approach and other components that are used in calculating the Network Use of System charge is contained in Figure 4. This diagram also shows where each component is addressed in our Regulatory Proposal.

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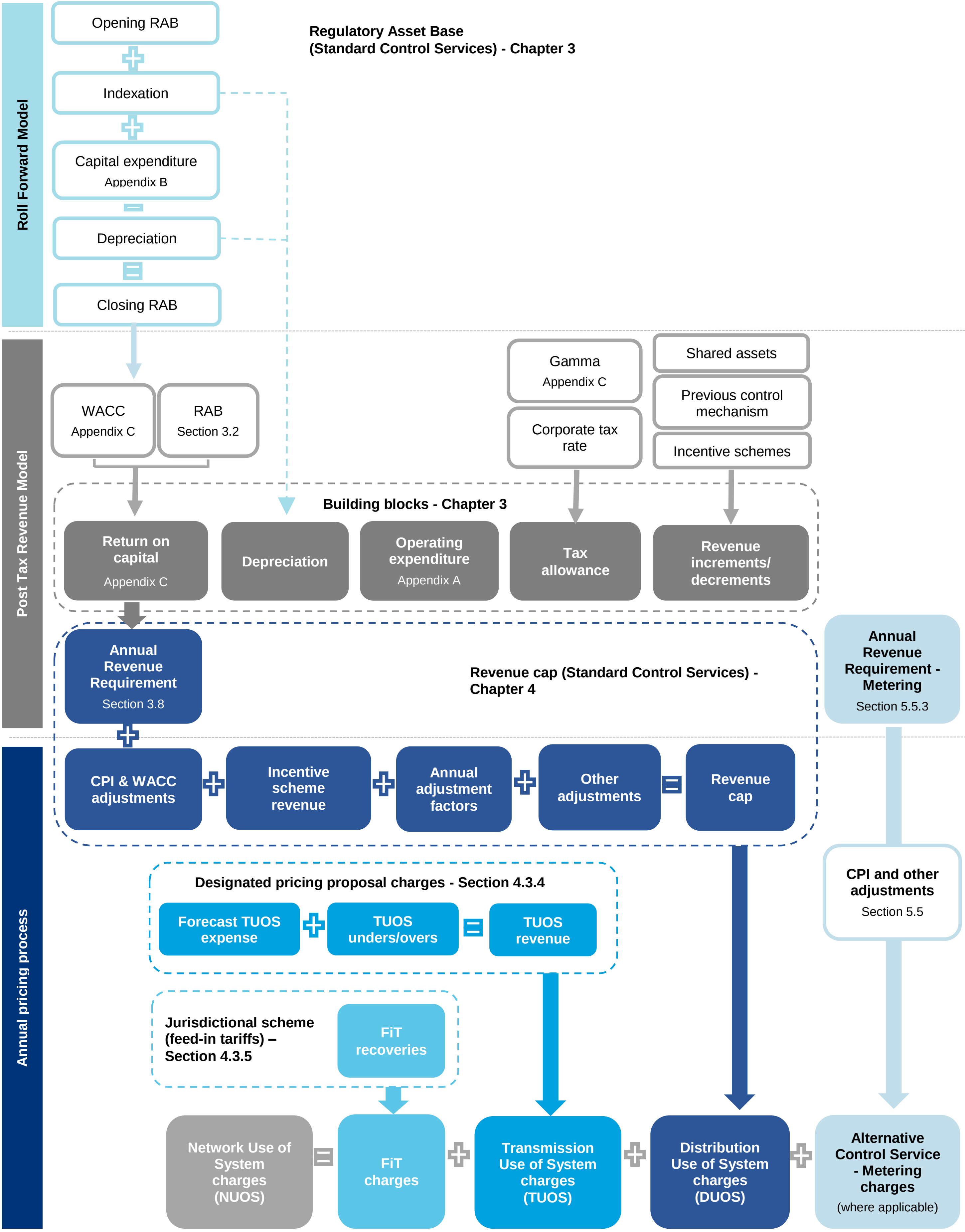
[28] NER, clause 6.4.3.

[29] Clause 6.4.2 of the NER requires the PTRM to set out how the ARR is to be determined. Further, clause 6.4.3 of the NER defines the building blocks that make up the ARR. We have interpreted these two clauses to mean the PTRM must include all building blocks set out in clause 6.4.3.

[30] Refer to *03.01.04 – Post Tax Revenue Model (May 2014)* and *03.01.05 – Post Tax Revenue Model (June 2008)*.

Figure 4: Components of the network bill and this Regulatory Proposal



3.2 Regulatory Asset Base

When Ergon Energy spends money on an asset, for example a new substation, we are not compensated immediately for our investment. Rather, the cost Ergon Energy incurs in building that substation is usually recouped over the number of years the substation is expected to remain in service.

Ergon Energy's RAB represents the remaining value of all the capital investments we have previously made and that is still required to be recovered from customers, taking into account:

- the amount of investment already recovered from customers (through the depreciation allowance)
- the amount of investment in new assets
- any proceeds from asset disposals
- increases or decreases in the value of previous investments because the asset is providing a different service or the service it is providing has changed classification.

The NER sets out the arrangements for how Ergon Energy's opening RAB is to be calculated. These arrangements, as well as the AER's own Roll Forward Model (RFM) and Guidelines, dictate how Ergon Energy's prior and future investments are incorporated into prices for customers.

3.2.1 Establishing the RAB

Ergon Energy's opening RAB value for the commencement of the next regulatory control period is shown in Table 3 below. This value has been derived by adjusting the value of the RAB at the beginning of first regulatory year of the current regulatory control period (i.e. 1 July 2010) and applying the AER's RFM.

In rolling forward the RAB, Ergon Energy has taken into account clause S6.2.1 of the NER, as well as other relevant transitional provisions.[31] A summary of the calculations made to derive the opening RAB as at 1 July 2015 are provided in Table 3. A more detailed explanation supporting the basis for these values is provided in supporting document *03.01.01 – Ergon Energy's building block components* (*Building Blocks supporting document*).

[31] NER, clause 11.16.3.

Table 3: Ergon Energy's Regulatory Asset Base, 2010-15

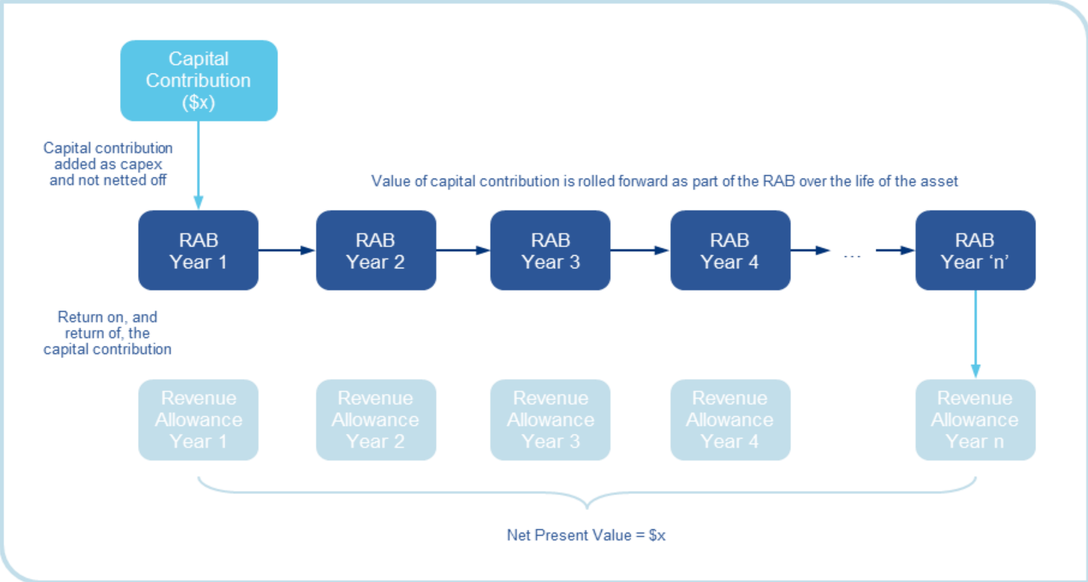
$m (nominal)	2010-11 Actual	2011-12 Actual	2012-13 Actual	2013-14 Actual	2014-15 Estimate
Opening RAB	7,160.95	7,858.05	8,360.76	9,006.79	9,606.34
plus capital expenditure (net of disposals and capital contributions)	801.49	758.16	827.95	748.54	885.91
less regulatory depreciation	(104.39)	(255.46)	(181.92)	(148.99)	(186.67)
less difference between actual and forecast net capital expenditure in 2009-10, and the return on difference for the net capital expenditure in 2009-10	-	-	-	-	(209.75)
Closing RAB	**7,858.05**	**8,360.76**	**9,006.79**	**9,606.34**	**10,095.83**
less adjustments to recognise changes in service classifications that occur on 1 July 2015	-	-	-	-	(54.29)
Opening RAB 1 July 2015					**10,041.54**

3.2.2 Capital Contributions

Under the transitional arrangements in clause 11.16.10 of the NER, the RAB that was used to determine the allowable revenue for the current regulatory control period included a value for the forecast capital contributions (both cash and gifted assets). Therefore, the calculated revenue included an allowance for return of, and on, the contributed assets. To avoid Ergon Energy earning revenue from assets we did not fund, the Distribution Determination included a revenue adjustment, which was equal to the value of the forecast capital contributions, in the year in which the capital contribution was forecast to occur. By definition, the net present value (NPV) of the revenue stream to be earned from the capital contributions over the life of those assets is equal to the initial value of the capital contribution. A conceptual illustration of this mechanism is provided in Figure 5.

As illustrated in the diagram, the capital contributions are not removed from the RAB as doing so would result in the NPV of the revenue stream from those assets being lower than the original value of the contributions (i.e. the original revenue adjustment would have been too high). Therefore, the value of the actual capital contributions for the current regulatory control period have been included in the roll forward of the RAB to 1 July 2015, so that the forward revenue calculations will continue to include an amount for the return on, and of, the past capital contributions.

Figure 5: Treatment of capital contributions under Chapter 11 of the NER



For the next regulatory control period, forecast capital contributions related to Standard Control Services will be netted off the gross capital expenditure to determine the net capital expenditure for calculating the allowable revenue, as per the PTRM. As a result, no revenue adjustment will be required for capital contributions received during the next regulatory control period.

3.2.3 Roll forward of the RAB

We have used the AER's PTRM to roll forward the RAB for Standard Control Services from 1 July 2015 to 30 June 2020. A summary of the roll forward values is provided in Table 4.

Table 4: Ergon Energy's forecast Regulatory Asset Base, 2015-20

$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Opening RAB	10,041.54	10,651.75	11,233.28	11,748.10	12,311.45
plus capital expenditure (net of disposals and capital contributions)	783.74	773.23	722.49	724.13	725.82
less regulatory depreciation	(173.53)	(191.70)	(207.66)	(160.77)	(170.28)
Closing RAB	**10,651.75**	**11,233.28**	**11,748.10**	**12,311.45**	**12,867.00**
Inflation rate	2.57%	2.57%	2.57%	2.57%	2.57%

Further details explaining the basis for the estimates of capital expenditure for the next regulatory control period are provided in Appendix B, and further details on the calculation of regulatory depreciation are provided later in this chapter.

3.2.4 Adjustments to the RAB

Ergon Energy has made adjustments for the following reasons:

- removal of assets that were (or will be) disposed during the regulatory control period 2010-15

- removal of assets from the RAB that will not be used to provide Standard Control Services in the next regulatory control period 2015-20
- inclusion of assets in the RAB that were previously unregulated, but which will be used to provide Standard Control Services in the next regulatory control period 2015-20.

Each of these adjustments are summarised briefly below.

Removal of assets due to disposals

The disposal of assets has been recognised in the roll forward of the RAB for Standard Control Services by reducing the opening asset base each year by the value of assets disposed during the regulatory year (refer to Table 3 and Table 4). This is in accordance with clause S6.2.1(e)(6) of the NER.

The value of the disposals for the current regulatory control period is based on the actual proceeds from sale, which is consistent with the approach used for forecasting disposals in the PTRM for the next regulatory control period.

Further details explaining the basis for the actual disposals recognised in the RFM for the current regulatory control period and the forecast disposals recognised in the PTRM for the next regulatory control period are provided in Chapter 2 of our *Building Blocks supporting document*.

Removal of assets due to service reclassifications

Ergon Energy has removed Type 5 and 6 metering assets from the RAB. These assets were included in the RAB in the regulatory control period 2010-15 as they were used in the provision of Standard Control Services. However, consistent with the requirements of clause S6.2.1(e)(7) of the NER, these assets were removed from the RAB following the AER's reclassification of Type 5 and 6 metering services as Alternative Control Services for the next regulatory control period.

Further details of the reduction to the RAB to recognise the reclassification of Type 5 and 6 metering services are set out in Chapter 2 of our *Building Blocks supporting document*.

Inclusion of assets due to service reclassifications

Ergon Energy has a number of assets that were not included in the RAB for the current regulatory control period, but which have been (or will be) included in the RAB for the next regulatory control period.

Consistent with clause S6.2.1(e)(8) of the NER, these assets have been included in the RAB because:

- they were never previously used to provide Standard Control Services
- the value of the assets have not been recovered through network charges for Standard Control Services
- these assets will be used in the next regulatory control period for the provision of regulated distribution services and, more specifically, Standard Control Services, consistent with the AER's classification of services.

The written down values of the assets have been recognised as capital expenditure in the RFM in the financial year in which the reclassification occurred. The values were disaggregated into the Standard Control Service asset classes that most appropriately aligned with the type of assets being transferred into the RAB.

Further details of the increase to the RAB to recognise the reclassification of the services provided by these assets are also found in Chapter 2 of our *Building Blocks supporting document*.

3.3 Return on capital

The allowed rate of return describes the return Ergon Energy is allowed to earn on the capital invested in the regulated distribution network. According to the NER, the allowed rate of return should be such that it achieves the rate of return objective, which is:

> "that the rate of return for a *Distribution Network Service Provider* is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the *Distribution Network Service Provider* in respect of the provision of *standard control services*".[32]

Ergon Energy has estimated an allowed rate of return of 8.02% for the regulatory control period 2015-20, which we consider achieves the rate of return objective. A detailed explanation of how the allowed rate of return is estimated is provided in Appendix C.

The return on capital for a regulatory year is calculated as the product of the opening RAB value and the allowed rate of return. Together with the opening RAB values estimated in Table 4 above, we have estimated the return on capital for Standard Control Services for each regulatory year of the next regulatory control period, as set out in Table 5.

Table 5: Return on capital for Standard Control Services, 2015-20

$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Return on capital	804.93	853.84	900.46	941.73	986.89

3.4 Return of capital (depreciation)

As noted above, Ergon Energy recoups the cost of any investment over the life of the asset. The regulated revenue includes an allowance representing recovery of part of the RAB, based on the age profile of the assets within the RAB and the method of calculating depreciation. The AER's PTRM requires the depreciation allowance to be offset by the indexation of the RAB (the net value is often referred to as the regulatory depreciation building block).

Our proposed regulatory depreciation for Standard Control Services for each year of the next regulatory control period is provided in Table 6.

Table 6: Depreciation for Standard Control Services, 2015-20

$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Return of capital	173.53	191.70	207.66	160.77	170.28

[32] NER, clause 6.5.2(c).

These forecasts have been calculated in accordance with clause 6.5.5 of the NER. Specifically, forecast depreciation has been calculated on the opening RAB value of each asset class using the straight-line depreciation methodology over the remaining standard life of the asset.

We have forecast our depreciation schedules by applying the AER's roll forward of the opening asset base and our forecast capital expenditure and disposals. A detailed explanation supporting the calculation of depreciation is provided in Chapter 4 of our *Building Blocks supporting document*. This supporting document also includes our estimates of the average standard and remaining lives of each asset class.

3.5 Operating expenditure

Table 7 sets out the forecast operating expenditure included in the PTRM for Standard Control Services for each year of the regulatory control period 2015-20.

These forecasts represent the requirements proposed by Ergon Energy to achieve the operating expenditure objectives outlined in clause 6.5.6(a) of the NER. A detailed explanation of the operating expenditure forecasts is included at Appendix A.

Table 7: Proposed operating expenditure, 2015-20

$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Operating expenditure forecasts	370.45	387.20	405.65	426.61	444.78

3.6 Corporate income tax

We have estimated the cost of corporate income tax for each year of the regulatory control period 2015-20 in accordance with the requirements of the PTRM, the RFM and clause 6.5.3 of the NER. The estimated amounts for each year in the next regulatory control period are provided in Table 8. Additional details on the approach and input variables used to calculate the cost of corporate income tax are provided in Appendix C and Chapter 6 of our *Building Blocks supporting document*.

Table 8: Estimated cost of corporate income tax for Standard Control Services, 2015-20

$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Corporate income tax	115.74	122.26	131.50	123.58	128.33

3.7 Revenue increments/decrements

In addition to the building blocks identified in the above sections, the NER makes provision for a number of adjustments that need to be made during the next regulatory control period 2015-20. Some adjustments are made directly in the calculation of the ARR as part of the building block approach (i.e. as a revenue increment or decrement). Other adjustments are made as part of the revenue cap calculation and/or in the annual Pricing Proposal (refer to Chapter 4).

This section sets out the revenue increments or decrements to the ARR, being:

- the carry forward of DUOS unders and overs from the current regulatory control period[33]
- two incentive schemes: [34]
  - EBSS
  - Demand Management Incentive Scheme (DMIS)[35]
- the use of shared assets.[36]

The revenue increments and decrements have been included in the PTRM as an individual line item within the operating expenditure input section, consistent with the approach noted in the PTRM Handbook.[37]

3.7.1 Carry forward of DUOS unders and overs

Under a revenue cap, our revenues are adjusted annually to clear any under or over recovery of actual revenue collected through DUOS charges. This 'unders and overs' process is undertaken as part of annual pricing and ensures the we recover no more and no less than the Maximum Allowable Revenue[38] approved by the AER for any given year.

To ensure customers did not experience any unnecessary price shocks as a result of clearing any significant DUOS under or over recoveries, the AER set tolerance limits in its Distribution Determination 2010-15. Where tolerance limits were triggered, we were required to spread the under or over recovery over multiple regulatory years, instead of clearing the entire under or over recovery in setting prices for the forthcoming year.

Our 2014-15 Pricing Proposal, which was approved by the AER on 13 June 2014, highlighted that we would have a residual balance of $53.57 million left in our DUOS unders and overs account as at 30 June 2015. We propose to clear this amount as a carry forward adjustment in the PTRM. Further information is contained in supporting document *03.01.02 – Other revenue adjustments*.

Chapter 4 outlines how DUOS under and over recoveries from 2013-14 to 2017-18 will be dealt with in the next regulatory control period.

3.7.2 Incentive schemes

The EBSS seeks to provide a financial incentive for Ergon Energy to improve the efficiency of our operating expenditure and to share any resulting efficiency gains (or losses) with our customers. Any efficiency gains (or losses) are retained by Ergon Energy for five years after the gain (or loss) is realised. This means the EBSS revenue adjustment in the next regulatory control period relates to our performance under the EBSS in the current regulatory control period.

Ergon Energy underspent our operating expenditure forecast in the current regulatory control period (refer to Appendix A). This has resulted in an overall EBSS reward for Ergon Energy in the

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[33] NER, clause 6.4.3(a)(6) – the application of the control mechanism in the current regulatory control period 2010-15.
[34] NER, clause 6.4.3(a)(5) – the application of incentive schemes (if any).
[35] NB – The NER has since changed the name of this scheme to 'Demand Management and Embedded Generation Connection Incentive Scheme' (DMEGCIS) to explicitly cover innovation with respect to the connection of embedded generation. According to the Framework and Approach Paper, the AER's current and proposed DMIS includes embedded generation.
[36] NER, clause 6.4.3(a)(6A).
[37] The PTRM Handbook states that any carry over amounts arising from the arrangements of the previous regulatory control period should be separately identified within the operating expenditure section of the PTRM input sheet.
[38] In the next regulatory control period, due to changes to the Standard Control Services formula, the Maximum Allowable Revenue will be referred to as the Total Allowed Revenue.

next regulatory control period which will be passed through to customers via network charges (see Table 9). These carry-over amounts are offset by longer term efficiency gains for customers. This is because reducing operating costs results in a lower base for our forecasts in the next regulatory control period and, ultimately, lower network prices.

The DMIS seeks to provide incentives to Ergon Energy to implement efficient non-network alternatives for managing expected demand on the network and efficiently connect embedded generators. In its Framework and Approach Paper, the AER proposed to apply Part A of the DMIS in the next regulatory control period (i.e. the Demand Management Innovation Allowance (DMIA)). Consistent with the Framework and Approach Paper, Ergon Energy has proposed a total DMIA allowance of $5 million over the next regulatory control period. For revenue modelling purposes, Ergon Energy has included the $5 million DMIA as a bottom up item in our operating expenditure forecast. To avoid double counting of the allowance, no further adjustments have been made to the revenue model.

The following table summarises the revenue adjustments included in the building blocks for these two incentive schemes.

Table 9: Estimated revenue adjustments associated with incentive schemes, 2015-20

$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
EBSS	37.54	55.09	79.67	(18.43)	0.00
DMIS (Part A, DMIA)	1.00	1.00	1.00	1.00	1.00

Further details on the incentive scheme revenue adjustments are provided in supporting document *03.01.03 – Application of Incentive Schemes*.

3.7.3 Shared assets

For the current regulatory control period 2010-15, we have applied clause 11.16.3 of the NER for the treatment of assets in the RAB. This has resulted in the inclusion of assets in the RAB which are used to provide Standard Control Services, Alternative Control Services and unregulated services.

To avoid double-recovery of costs, we have applied an offsetting revenue adjustment consistent with the AER's Distribution Determination 2010-15. This ensures:

- we are not recovering revenue twice for the same assets
- customers are only paying for the costs of assets that are only used to provide Standard Control Services.

We propose to adopt this same approach in the next regulatory control period.[39] This means the opening RAB value at 1 July 2015 contains values for assets that are used to provide Standard Control Services, Alternative Control Services and unregulated services. Consistent with the current arrangements, we propose to apply an offsetting revenue adjustment, equivalent to the sum of the depreciation and return on assets, for the component of the shared assets that are used for purposes other than Standard Control Services.

[39] With the exception of the true-up adjustment in the annual Pricing Proposal, which took into account the difference between the forecasts included in our revenue building blocks and our actual shared assets revenue.

We are of the view that this approach aligns with the principles of the shared asset mechanism outlined in the AER's Shared Asset Guideline, that customers should not pay for more than their fair share for shared assets and that service providers may propose their own cost reductions. Further, the proposed revenue adjustment is equivalent to the control, which sets a cap on the quantum of the cost reduction.

We note that the Shared Asset Guideline only contemplates the situation where assets are used to provide Standard Control Services and unregulated services. The Shared Asset Guideline does not appear to consider the situation where assets are used to provide Standard Control Services and Alternative Control Services. Given this, we propose to continue to adjust for Alternative Control Services in our revenue adjustment calculations.

Table 10 outlines our proposed revenue decrements resulting from the use of shared assets. A more detailed explanation justifying the basis of our methodology, together with the calculations used to derive the offsetting revenue adjustments is provided in supporting document *03.01.02 – Other revenue adjustments*.

Table 10: Estimated revenue adjustment associated with the use of shared assets, 2015-20

$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Revenue adjustment - shared assets	(6.02)	(6.18)	(6.33)	(6.50)	(6.66)

3.8 Annual Revenue Requirement

Ergon Energy's ARR for Standard Control Services, broken down by each building block component, for the regulatory control period 2015-20 is provided in Table 11. These amounts have been calculated using the AER's PTRM, which is included in supporting document *03.01.04 – Post Tax Revenue Model.*

Table 11: Annual Revenue Requirement, 2015-20

$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Return on capital	804.93	853.84	900.46	941.73	986.89
Return of capital	173.53	191.70	207.66	160.77	170.28
Operating expenditure	370.45	387.20	405.65	426.61	444.78
Corporate income tax	115.74	122.26	131.50	123.58	128.33
Other adjustments	90.08	48.92	73.34	(24.92)	(6.66)
Building Block Revenue (unsmoothed)	1,554.74	1,603.92	1,718.60	1,627.77	1,723.61
Annual Revenue Requirement (smoothed)	**1,511.09**	**1,598.46**	**1,703.82**	**1,710.69**	**1,717.60**

3.9 X-factors

As noted in the PTRM Handbook, the X-factor is a price or revenue adjustment mechanism applied to the ARR to smooth the ARR over the regulatory control period and avoid price shocks between regulatory control periods.

The AER sets the X-factors consistent with the NER. This includes:

- designing the X-factors to equalise, in NPV terms, the revenue Ergon Energy can earn from the provision of Standard Control Services with the total revenue requirement for the regulatory control period
- minimising the variance between expected revenue for the last regulatory year and the ARR for that year.

This is normally achieved by making a Year 1 adjustment, and holding the smoothing adjustments in Years 2 to 5 at a constant rate (i.e. a constant 'X'). As the X-factors are only applied to revenue requirements included in the PTRM, the smoothing does not take into account other adjustments to the ARR undertaken in the annual Pricing Proposal process.

In Ergon Energy's case, our revenues are adjusted annually to incorporate a number of other revenue adjustments included in the Standard Control Services formula. For example, the Total Allowed Revenue in 2015-16 includes the smoothed ARR plus adjustments for:

- a financial reward for our performance under the STPIS in 2013-14
- a Solar Bonus Scheme cost pass through amount relating to FiT payments made in 2013-14
- any DUOS under or over-recovery amount from 2013-14
- any under or over-recoveries relating to capital contributions and shared assets from 2013-14.

The result of the magnitude of forecast adjustments in 2015-16 and 2016-17 mean that even if Ergon Energy targeted a reduction in ARR, customers could face increases in changes for those years. As noted in Chapter 1, through our engagement program we have a clear understanding of the level of concern about rising electricity prices and the traditional approach to calculating X-factors would result in unacceptable outcomes. As part of our customer commitments, we have therefore targeted smoothed ARRs (through X-factor adjustments) that allow a reduction in DUOS revenue (excluding FiT) in the first year.

Ergon Energy's proposed X-factors for Standard Control Services for each year of the next regulatory control period are detailed in Table 12.

Table 12: X-factors for Standard Control Services, 2015-20

	2015-16	2016-17	2017-18	2018-19	2019-20
X-Factors	15.85%	(3.13%)	(3.92%)	2.11%	2.11%

Ergon Energy has calculated the proposed X-factors for each year of the next regulatory control period in the PTRM, in accordance with the requirements of clause 6.5.9 of the NER. In particular, Ergon Energy has set the X-factors consistent with the NER.

3.10 Applying 2015-20 incentive schemes

The AER's Framework and Approach Paper proposed to apply the following incentive schemes to Ergon Energy in the next regulatory control period:

- DMIS
- EBSS
- STPIS
- Capital Expenditure Sharing Scheme (CESS).

The objectives of these schemes are to provide financial incentives to DNSPs to make efficient investment decisions and to maintain and improve the efficiency of their expenditure, performance or services over time.

Ergon Energy supports the AER's proposed approach to the application of each scheme. However, we suggest that in the application of the CESS the AER should consider the potential impacts on the operation of the CESS that may be generated by Customer Connection Initiated Capital Works expenditure being above or below the expected AER allowances or forecasts for the next regulatory control period or by decisions by a DNSP to not apply for pass throughs for events that may meet the threshold but generate capital costs that could contribution to over-expenditure of allowances. The latter concern also applies to the operation of the EBSS. Further detail is provided in our supporting document *03.01.03 – Application of Incentive Schemes*.

It should be noted that the method and timing of the revenue adjustments associated with these incentive schemes vary, as shown in Table 13. As such, this Regulatory Proposal does not cover revenue increments or decrements associated with the next regulatory control period's EBSS and CESS.

Table 13: Adjustments associated with application of incentive schemes in 2015-20

Incentive scheme	Method and timing of adjustment	Section
DMIS	Revenue increment in the ARR calculation in 2015-20	Section 3.7.2
EBSS	Revenue increment/decrement in the ARR calculation in 2020-25. There will be no revenue impact in 2015-20.	N/A
STPIS	Adjustment to the ARR during the annual Pricing Proposal process. There is generally a two year lag between the performance year and the pass through of the reward or penalty in prices.	Section 4.2.1
CESS	Revenue increment/decrement in the ARR calculation in 2020-25. There will be no revenue impact in 2015-20.	N/A

3.11 Supporting documentation

The following documents referenced in this chapter accompany our Regulatory Proposal:

Name	Ref	File name
Ergon Energy's Building Block Components	03.01.01	Building Block Components
Other Revenue Adjustments	03.01.02	Other revenue adjustments
Application of Incentive Schemes	03.01.03	Ergon Energy Incentive Schemes
Post Tax Revenue Model (May 2014)	03.01.04	SCPTRM Data Model AER May 2014 Version
Post Tax Revenue Model (June 2008)	03.01.05	SCPTRM Data Model AER June 2008 Version
Roll Forward Model	03.01.06	SCRFM Data Model