


06.01.04

Step Changes for Operating Costs

Revision history

Version	Date	Summary of changes
1.0	31 October 2014	As submitted to the AER as part of the initial Regulatory Proposal
2.0	3 July 2015	Revisions made to reflect: • a 2013-14 base year • removal of the non-network alternatives and AEMO Testing Requirements – Metering Preventative step changes • introduction of two new step changes relating to parametric insurance and the Market Transaction Centre.

Contents

1 Introduction

Ergon Energy's base step trend (BST) forecast methodology allows for necessary adjustments to be made to operating expenditure rolled forward on a recurrent basis (steps). This may happen for a number of reasons, including changes to obligations or transfers between capital and operating expenditure.

Ergon Energy has had regard to the Australian Energy Regulator's (AER) requirements for determining step changes and has considered which step changes should be added (or subtracted) for any 'other costs' not captured in the base year operating expenditure. The AER sets out specific criteria for the determination of a step change in expenditure. We do not necessarily agree with the AER's proposition that expenditure must meet its criteria for a step change to be justified.

The National Electricity Rules (NER) takes primacy in this regard and it is important to note that there is no mention of step changes in the NER. The Australian Energy Market Commission (AEMC) made it clear that the determination of what is an efficient forecast should be the absence of limiting criteria:

> "the NER do not place any restrictions on the analytical techniques that the AER can use to scrutinise and, if necessary, amend or substitute the NSP's capex or opex forecasts"[1]

This document describes the proposed step changes included in Ergon Energy's BST operating expenditure forecast for the regulatory control period 2015-20. For operating expenditure forecast purposes, Ergon Energy proposes the following step changes to direct costs:

Table 1 Step changes to direct costs

Step changes to direct costs $2013-14m	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Market Transaction Centre	5.2	-	-	-	-	5.2
Parametric insurance	13.0	-	-	-	-	13.0
Total	**18.2**	**-**	**-**	**-**	**-**	**18.2**

In addition to step changes to direct costs, Ergon Energy proposes an increase in expenditure trend in overheads for Information and Communication Technology (ICT) Asset Service Fees (ASFs) and operational and licence fee increases arising from associated ICT capital expenditure. The step change is outlined in the following table:

1 AEMC (2012), Rule determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, 29 November 2012, p28.

Table 2 Step changes to overhead costs

Step changes to direct costs $2013-14m	2015-16	2016-17	2017-18	2018-19	2019-20	Total
ICT ASF and related costs	(1.7)[2]	7.95	5.45	6.28	5.02	23.53
Operational and licence fee increases	5.0					5.00
Total	**3.3**	**7.95**	**5.45**	**6.28**	**5.02**	**28.53**

The following sections provide more detail regarding the step changes listed.

[2] Ergon Energy's BSTey model includes a negative step change from 2013-14 to 2014-15 of $6.12 million and then a positive step change from 2014-15 to 2015-16 of $4.96 million.

2 Parametric insurance

The following table summarises Ergon Energy's proposed step change for parametric insurance:

Requirement	Response
Description of the step change	The base year expenditure does not include expenditure relating to efficient and prudent level of insurance cover required to mitigate the financial risks Ergon Energy faces in relation to damage caused to our electricity network by large scale storm and cyclone events. This is because, historically, there has been a lack of available and efficiently priced insurance cover in the insurance markets
Detailed description of the driver of the step change	Ergon Energy's electricity network or 'poles and wires' assets are vulnerable to significant damage or loss caused by storms and cyclones as a result of being located in a tropical climate zone. Historically, Ergon Energy has not insured our electricity network assets against major damage or loss caused by storms and cyclones because of a lack of available and efficiently priced insurance cover in the insurance markets and has relied on the cost pass through mechanism available under the NER.
Detailed description of the projects incurring the proposed expenditure	Our supporting documentation (outlined below) provides details of the relevant costs associated with the step change in expenditure.
Year in which the expenditure is first incurred	It is likely that the insurance will be procured in the first year of the regulatory control period (i.e. 2015-16).
Breakdown of the expenditure for each year in the forecast period	Refer to Table 1 above.
Demonstration of how the expenditure amounts have been calculated	Our supporting documentation (outlined below) provides details of the relevant costs associated with the step change in expenditure.
Cost benefit or comparable analysis	Our supporting documentation (outlined below) provides details of the relevant costs associated with the step change in expenditure.
Capital expenditure / operating expenditure trade-off	It is important to note that the impacts of events which the parametric insurance cover are not in the forecast. Additional costs would be borne by consumers in the future through pass through mechanisms in the absence of the step change, and also through re-inclusion of costs excluded from our capital and operating expenditure forecasts based on estimated insurance proceeds that would be received over the period.
Demonstration that the proposed step change has not contributed to a double counting of cost	There is no double counting of cost in the forecasts as there is no provision for expenditure when a cyclone occurs in the forecast.
How the step change satisfies the operating expenditure objectives and criteria	We note our documentation supporting the step change (outlined below) provides reasoning as to why the step change is necessary. The statements made by the AEMC and the AER are unambiguous in requiring Distribution Network Service Providers (DNSPs) to manage risks, including risks associated with major natural disasters, if it is at all possible to do so. Wherever it is feasible, from a cost standpoint, to manage risks through the commercial insurance market, this is to be preferred to transferring that risk to customers via a cost pass through.

Requirement	Response
Evidence that the need for the project or program has been endorsed through relevant governance arrangements	The proposed expenditure on parametric insurance has been assessed has part of our AER Forecast Review Committee process. It has also received support and consideration by various Board sub-committees and the Board itself.

2.1 Driver of step change

Ergon Energy's electricity network or 'poles and wires' assets are vulnerable to significant damage or loss caused by storms and cyclones as a result of being located in a tropical climate zone.

Our approach in the regulatory control period 2010-15 to funding damage or loss of electricity network assets caused by typical storms and low category rated cyclones is through a combination of the operating expenditure (forced maintenance) and capital expenditure (asset replacement) allowances set by the AER.

For large storms and high category rated cyclones, Ergon Energy may fund the cost by using the cost pass through provisions in the NER.[3] Historically, Ergon Energy has not insured our electricity network assets against major damage or loss caused by storms and cyclones because of a lack of available and efficiently priced insurance cover in the insurance markets and we have relied on the cost pass through mechanism provisions, where appropriate.

Insurance premiums for both businesses and households reflect the risk profile at the applicable geographic location. Though other factors are taken into consideration, the hazard signal leads to heightened premiums, especially in high hazard areas.

In recent years insurance markets have matured, with some insurers now prepared to offer insurance to electricity Transmission Network Service Providers (TNSPs) and DNSPs operating not only in Europe and the United States but also increasingly in Asia. To that end, and consistent with NER requirements and AEMC guidance, Ergon Energy has worked with our insurance broker, Aon and its affiliate Risk Solutions International (RSI), to develop options for traditional insurance and parametric insurance, respectively, to cover the cost of damage or loss of electricity network assets caused by storms and cyclones.

Ergon Energy has identified a parametric insurance product that will address applicable NER requirements and provide an efficient and prudent level of insurance cover to mitigate the financial risks we face in relation to damage caused to our electricity network by large scale storm and cyclone events. Further details of the proposed approach can be found in our supporting document, *06.02.03 – Parametric Insurance Report*.

2.2 Justification of step change

Our proposal provides necessary evidence to justify the increase in expenditure for parametric insurance. This includes:

- *06.02.03 – Parametric Insurance Report*
- *Opex (General) – Response*.

[3] NER, clause 6.6.1.

An efficient Network Service Provider (NSP) has an obligation to consider whether insurance can be obtained to cover damage or loss of electricity assets caused by storms and cyclones. If insurers offer it on reasonable commercial terms, then the insurance should be obtained. If an NSP can obtain insurance cover for catastrophic events, such as cyclones, at a cost that reflects a prudent and efficient expenditure in customers' long term interests, then the NER and the AER's own statements clearly indicate that these costs should be approved as a risk transfer mechanism in preference to the cost pass through provisions in the NER.

3 Market Transaction Centre

The following table summarises Ergon Energy's proposed step change for the Market Transaction Centre:

Requirement	Response
Description of the step change	Anticipated costs of meeting new regulatory obligations through our Market Transaction Centre, as the Minimalist Transitioning Approach reaches an end.
Detailed description of the driver of the step change	Refer to changes in regulatory obligations and the impact on costs below.
Detailed description of the projects incurring the proposed expenditure	Detailed descriptions of the costs are included in the attached business case.
Year in which the expenditure is first incurred	Expenditure will be incurred in 2015-16 and will be ongoing.
Breakdown of the expenditure for each year in the forecast period	There will be a step change of $5.2 million in 2015-16 related to the Market Transaction Centre additional costs. We forecast total expenditure consistent with trends already included in our Regulatory Proposal.
Demonstration of how the expenditure amounts have been calculated	Detailed descriptions of the costs are included in the attached business case
Cost benefit or comparable analysis	Cost benefit and comparable analysis is included in the attached business case
Capital expenditure / operating expenditure trade-off	Not applicable
Demonstration that the proposed step change has not contributed to a double counting of cost	This is an incremental cost to activities already undertaken. A change to regulatory requirements makes it clear that additional costs will be required. This is detailed below and in supporting documentation.
How the step change satisfies the operating expenditure objectives and criteria	The evidence is conclusive that the step change will assist in establishing a total forecast required to meet the operating expenditure objectives, is realistic in terms of the cost inputs and meets the criteria.
Evidence that the need for the project or program has been endorsed through relevant governance arrangements	The business case supporting the step change is attached. The Ergon Energy ICT Plan is approved through Ergon Energy's Investment Review Committee process. Evidence that the need for the project or program has been endorsed through relevant governance arrangements. A Joint Market Transaction Centre options paper and business case was approved by the Executive Leadership Team on 21 May 2014. The Market Transaction Centre was also part of the overall Beyond Minimalist Transitional Approach (MTA) Program paper submitted to the Ergon Energy Board. This paper was approved on 20 May 2014. A Services Agreement has also been signed by the Chief Executive of Ergon Energy and the Chief Executive Officer of Energex, as delegated by the respective Boards of each organisation. This agreement states the legal and commercial terms relating to the provision of the services. An executive steering committee has been established to oversee the execution of the Joint Market Transaction Centre arrangements under the agreement.

3.1 Proposed step change

Ergon Energy noted at the time of our October Regulatory Proposal that in the event the Queensland Competition Authority (QCA) revokes the MTA, a further step change would be required to be included in Ergon Energy's revised Regulatory Proposal. Our forecasts include a step change in expenditure to incorporate the anticipated costs of meeting new regulatory obligations through our Market Transaction Centre, as the MTA reaches an end. We expect this regulatory obligation to occur in the regulatory control period 2015-20 and we will begin to incur costs in 2015-16 to meet this obligation.

3.2 Driver of step change

In July 2007, Full Retail Competition commenced in Queensland's electricity market, allowing all Queensland customers connected to the National Electricity Market (NEM) to choose their electricity retailer.

When a retailer prepares a market offer for a customer, it needs certain information relevant to that customer, such as the National Metering Identifier (NMI), address, distribution loss factor etc. This information is generally available through the Market Settlement and Transfer Solution (MSATS). Where the information is not available in MSATS, distributors are required to provide customer NMI information within one business day of receiving a request from a retailer. The under the MSATS Procedures: Consumer Administration and Transfer Solution Procedures Principles and Obligations.

Under clause 4.4 of the Electricity Distribution Network Code (EDNC),[4] Ergon Energy is currently allowed to operate under a less onerous arrangement in comparison to other distributors when processing information requests from retailers. This regime is known as the the MTA. Under the MTA, Ergon Energy is only required to populate NMI data in MSATS where:

- the NMI is classified as 'Large'
- the NMI is classified as 'Small' and is the subject of a transfer request by a retailer.

This means the majority of Ergon Energy's NMIs are not published in MSATS. Further, Ergon Energy has two business days to provide requested NMI information to a retailer,[5] although we must maintain the capacity to process 150 NMI information requests in one business day.[6]

Since Ergon Energy's manual system does not interface with the MSATS system, a retailer must request Ergon Energy to "create the NMI" once it has contracted a new customer in Ergon Energy's distribution region. To "create the NMI", Ergon Energy provides AEMO with the customer's NMI information to populate the MSATS system.

Under the MTA, Ergon Energy has two business days to "create the NMI" once we are requested to do so by a retailer,[7] although we must have the capacity to process 40 NMI creation requests in one business day.[8]

[4] Previously the Electricity Industry Code.
[5] EDNC, clause 4.3.2.
[6] EDNC, clause 4.4.2(a).
[7] EDNC, clause 4.3.1.
[8] EDNC, clause 4.4.3(a).

The EDNC currently provides for Ergon Energy to operate under MTA until such time as the QCA issues a notice declaring it will no longer do so. The QCA is required to review on an annual basis whether the MTA should remain in place.[9] If the QCA considers that the MTA should no longer apply, it may issue Ergon Energy with a notice to this effect and the MTA would cease to apply from 12 months after the date of the notice. [10] When the MTA was implemented, the confidential triggers for moving off the MTA were agreed with the Queensland Government. In February 2015, Ergon Energy advised the QCA that one of these triggers had been met and, as a result, we believed the MTA should be removed. In accordance with the requirements of the EDNC, and following advice from Ergon Energy, the QCA is currently consulting on the removal of the MTA.[11]

If this occurs, market data for approximately 720,000 NMIs in Ergon Energy's distribution area will be validated and published to AEMO's MSATS system. Currently, approximately 18,500 NMIs are published to the market using the existing systems. Further, of the 300,000 (plus) service orders processed last year, only approximately 1,500 were received and processed through the market business-to-business procedures. If the MTA ceases, all service orders will be received and processed via the market.

This rise in market transaction activity and validation requirements will drive a larger volume of data exceptions; which will lead to an increased amount of manual intervention points and therefore increased resource levels required to perform this work to remain market compliant. While the new system capability enables full market compliance, the secondary consideration in being fully market compliant is the establishment of an effective and efficient service delivery capability to manage the transactional environment effectively.

3.3 Justification of step change

Ergon Energy's recurrent operating expenditure is based on MTA arrangements. We noted in our supporting document, *01.01.01 – Legislative and Regulatory Obligations and Policy Requirements,* that removal of the MTA would require Ergon Energy to make significant investments in systems and processes to enable compliance with the NER, the EDNC and other AEMO requirements.

The establishment of an automated distribution market solution prepares Ergon Energy for any significant increases in the volumes of customer transfers by automating this process. A potential shift of the Queensland Government's Community Service Obligation (CSO) payment to the Ergon Energy distribution business (from the retail business, Ergon Energy Queensland Pty Ltd) would increase the amount of churn significantly. While a CSO shift may not be a priority for the Queensland Government at this time, the systems, processes and capability will be in place to allow for a significant increase in retailer churn as well as catering for any other increases to customer transfer volumes experienced due to other initiatives. Increased network and retail tariff reform aimed at better cost reflectivity of energy services in end customer pricing, is also creating a platform for increases in customer churn between retailers.

Details of the costs and benefits, and specific functions can be found in the attached supporting document, *06.02.11 – Market Transaction Centre – Step change summary*.

[9] EDNC, clause 4.4.1(c).
[10] EDNC, clause 4.4.1(b).
[11] Refer http://www.qca.org.au/getattachment/26934be9-a03b-48b1-80a1-8495d8432e33/Consultation-Paper.aspx.

4 Non-network ICT

The following table summarises Ergon Energy's proposed step change for non-network ICT:

Requirement	Purpose
Description of the step change	The proposed step change relates to expenditure that is required in the regulatory control period 2015-20 that is not reflected in the 2013-14 base year for BST forecasting purposes. It includes expenditure for ICT capital works that were approved in the regulatory control period 2010-15 but were delivered after the 2013-14 year, including: • Market Systems (PEACE, Contact Centre Technology) • Work Force Automation (FFA).
Detailed description of the driver of the step change	Refer to the information below.
Detailed description of the projects incurring the proposed expenditure	Refer to the attached business cases: • 06.02.08 – BMTA Gate 3 Business Case • 06.02.09 – Contact Centre Technology Business Case • 06.02.10 – FFA Phase 1 Gate 3 Business Case IRC.
Year in which the expenditure is first incurred	Increases in operating expenditure are forecast to commence in 2014-15 for Network customer information system, Work Force Automation and Contact Centre Technology.
Breakdown of the steps for each year of forecast period	Refer to Table 2 above.
Demonstration of how the expenditure amounts have been calculated	Details of the forecast expenditure requirements can be found in Ergon Energy's Forecast Expenditure Summary – Information Communication and Technology (07.00.07) and Table 4 of the Ergon Energy ICT Plan 2015-20 (07.07.02).
Cost benefit or comparable analysis	Each program included in the Ergon Energy ICT Plan 2015-20 is subject to the Ergon Energy gated business case approval process and supported by a cost benefit analysis which quantifies the financial costs and benefits, assumptions made and sources of cost information used, options analysis and recommendations. The ASF related to these investments represent a legitimate capital expenditure/operating expenditure trade-off. The following investments made in the regulatory control period 2010-15 have resulted in a step change in ICT operating costs not reflected in the revealed cost base year: • Network customer information system (PEACE). • Work Force Automation (FFA). • Contact Centre Technology (CCT). Step change expenditure related to the above ICT investments is required to develop capabilities to meet new regulatory obligations as a consequence of removal of the MTA.

Change in operating environment	Ergon Energy confirms that:
	• the costs listed in the proposed step change relate both to support costs for:
	  o AER approved ICT works in the regulatory control period 2010-15 but not included in the revealed base year costs, and
	  o individual programs where Ergon Energy has undertaken a cost benefit analysis
	• the costs listed in the proposed step change cannot be met from existing regulatory allowances or from other elements of the expenditure forecast for the regulatory control period 2015-20.

Requirement	Purpose
Demonstration that the proposed step change has not contributed to a double counting of cost	Ergon Energy confirms that: • the proposed costs of the additional step change amount are not compensated through the output measure in the rate of change or accounted for in the forecast productivity growth • the additional proposed step change costs are efficient and either have a positive business case, or meet the NER objective to meet or manage the expected demand for Standard Control Services and comply with applicable regulatory obligations or requirements associated with the provision of Standard Control Services.
How the step change satisfies the operating expenditure objectives and criteria	The proposed step change in expenditure is required to provide a level of ICT support necessary to meet and manage the expected demand for Standard Control Services in the regulatory control period 2015-20 and comply with applicable regulatory obligations and requirements associated with the provision of standard control services. The expenditure for services is tested in the market via a panel arrangement and/or competitive tendering. As noted above, each program is subject to Ergon Energy's gated business case approval process.
Evidence that the need for the project or program has been endorsed through relevant governance arrangements	Business cases and relevant information has been provided to the AER in response to information requests.

4.1 Proposed step change

The AER's Expenditure Forecast Assessment Guideline makes it clear that:

> If it is efficient to substitute capex with opex, a step change may be included for these costs (capex/opex trade-offs).[12]

The AER's Preliminary Determination for Ergon Energy makes a similar point:

> One situation where a step change to total opex may be required is when a service provider chooses an operating solution to replace a capital one. For example, it may choose to lease vehicles when it previously purchased them. For these capex/opex trade-off step changes, we will assess whether it is prudent and efficient to substitute capex for opex or vice versa. In doing so we will assess whether the forecast opex over the life of the alternative capital solution is less than the capex in NPV terms.[13]

[12] AER (2013), *Better Regulation, Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p24.
[13] AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 7 – Operating expenditure*, April 2015, p303.

Ergon Energy's forecast for 2015-20 includes expenditure not reflected in the 2013-14 reported operating expenditure. It relates to:

- expenditure for the SPARQ Solutions Pty Ltd (SPARQ) support functions for ICT capital works that were approved in the regulatory control period 2010-15 but were delivered after the 2013-14 year
- expenditure for SPARQ support functions for ICT capital works that were in addition to the approved 2010-15 capital works program but were justified by cost benefit analysis undertaken by Ergon Energy.

Non-Capital Project Costs

Non-Capital Project Costs are non-recurrent operating expenditures that include ICT project specific expenses that cannot be capitalised under accounting standards and policies. These costs arise as a direct result of the ICT Program of Work (PoW) for Ergon Energy.

Asset Service Fees

Asset Service Fees include ICT asset depreciation, amortisation and ICT asset financing costs associated with assets held by SPARQ Solutions on behalf of Ergon Energy. The SPARQ ICT capital expenditure forecast is described in the Ergon Energy ICT Expenditure Forecast Overview.

The ICT asset financing cost is calculated based on the Weighted Average Cost of Capital (WACC) and the written down value of the ICT assets.

ICT depreciation is derived from tangible ICT assets held by SPARQ. ICT amortisation is derived from intangible ICT assets held by SPARQ. The ICT depreciation and amortisation is calculated based on the acquired cost of the ICT asset and scheduled over the useful life of the asset. The useful life of the ICT asset as defined in the ICT infrastructure asset renewal and ICT application asset management guidelines.

These costs are driven by the WACC, ICT PoW, economic life of the asset, and the age profile of the ICT assets held by SPARQ.

Associated operating expenditure requirements

Ergon Energy has been operating under limited market arrangements which has not justified investment in the contemporary market systems that most DNSPs would have in place. As a prudent DNSP, Ergon Energy has deferred investment in such systems pending clear direction that contestable market capability would be required. This direction was provided in 2014 and prudent ICT investments were initiated to provide such capability.

During the regulatory control period 2010-15, Ergon Energy implemented the following new ICT functionality, the operating costs for which were not represented in the 2013-14 revealed base year:

- Network customer information system (PEACE)
- Work Force Automation (FFA)
- Contact Centre Technology (CCT).

On this basis, Ergon Energy has included increased operating expenditure for a range of systems required to operate in a fully contestable market (changing from vertically integrated systems to independent systems operating via market interfaces). These systems provide enhanced customer information and network billing capability, field force automation, and contact centre capability. These systems allow Ergon Energy to operate in a fully contestable market place, bringing customer benefits in terms of choice, expanded service and National Energy Customer Framework compliance.

Further detail to support the programs can be found in Ergon Energy's Forecast Expenditure Summary – Information Communication and Technology.

4.2 Justification of step change

Ergon Energy has provided the following suite of evidence in justification of the step change:

- *07.00.07 – (Revised) ICT Expenditure Forecast Summary*
- *Capitalised Overheads and ICT Expenditure – Response*
- *KPMG – SPARQ ICT expenditure forecasts*.[14]

In addition, we have provided additional evidence in response to specific AER questions including business cases, which have contained detailed cost build-ups for the projects and cost benefit analysis justifying their implementation for the following proposed ICT SPARQ projects.

All of the above information is relevant for the justification of the step change. We note the following points as pertinent to the need for inclusion of additional expenditure to cater for ICT costs:

- SPARQ has advised from their reading of the Preliminary Determination that some of the characteristics of the unique SPARQ joint ICT arrangement have been misinterpreted / misunderstood by the AER and its consultants.
- ICT services for Ergon Energy are provided by SPARQ. SPARQ is a jointly owned subsidiary between Ergon Energy and Energex. The motivation for forming SPARQ was to create economies of scale, resulting in an overall cost reduction for the provision of ICT capability.
- The model is unique within the NEM. However, the broader substitution of ICT capital expenditure with ICT operating expenditure through trends such as Software as a Service (SaaS) and other 'Cloud' sourced solutions reflects the changing landscape of ICT and the potential for increases in ICT operational expenditure over increases in the Regulatory Asset Base associated with ICT investments. Ergon Energy should not be penalised for adopting more efficient delivery models.
- To allow meaningful comparison against the AER allowance, SPARQ operating expenditure needs to be adjusted for expenditure allocated to non-regulated Ergon Energy activities in accordance with what the AER approved as the appropriate allocation method (through the Cost Allocation Method).
- KPMG independently assessed the SPARQ arrangements and concluded that there is no material difference to the maximum allowed revenue under the AER's Post Tax Revenue Model (PTRM). This would suggest in Net Present Value (NPV) terms, there is no material difference between adopting traditional in-house capitalisation of ICT projects and the opex arrangement through SPARQ **unless the AER rejects the step change in operating expenditure for capital expenditure already incurred**. In the circumstance where the AER does reject the step change, there is a material difference between the two arrangements suggesting the AER has not properly considered substitution possibilities between capital and operating expenditure.

[14] KPMG (2015), *Report to the Board of SPARQ Solutions on ICT Expenditure Forecasts for the Period: 2015-20*, 25 June 2015.

- For Ergon Energy, the SPARQ methodology produces results that are approximately 2.6% less than the NPV of the PTRM regulatory equivalent.