Capital Expenditure Forecast

Unit Cost Methodologies Summary

2015 to 2020

Contents

1. About this summary document

This section explains the purpose and structure of this summary document.

1.1 Purpose

The purpose of this summary document is to explain and justify the methodologies applied by Ergon Energy to develop unit cost estimates for its Standard Control Services (SCS) and Alternative Control Services (ACS) for the next regulatory control period, 1 July 2015 to 30 June 2020. The cost estimates provide the building blocks for the network capital expenditure forecast and specifically apply to the following capital expenditure categories:

- Customer Initiated Capital Works
- Augmentation Expenditure
- Renewal Expenditure
- Reliability and Power Quality Expenditure
- Other System and Enabling Technology Expenditure

This document should be read in conjunction with the 'Forecast Expenditure Summary' documents for each capital category listed above. While this document aims to provide the reader with a full understanding of Ergon Energy's unit costs, this is a summary document and therefore addresses some matters at a relatively high level. Further, the document references other documents and appendices in the provision of additional detail and clarification.

All unit costs presented in this document are in real 2012-13 dollars. At the time of preparation, this ensures unit costs align with the most recent audited financial statements being the 2012-13 year. Escalation of the network capital expenditure forecasts, for Ergon Energy's regulatory submission, is to real 2014-15 dollars.

Importantly, this summary document only explains and justifies Ergon Energy's direct estimated costs. Ergon Energy applies real cost escalations and shared costs (overheads) to these direct costs to determine its total capital expenditure. Ergon Energy has prepared, and provided to the Australian Energy Regulator separate documents that explain and justify, for all of its capital expenditure categories, how it applies these real cost escalations and shared costs (overheads).

Readers should take care in examining the (un-escalated) direct costs in this summary document to avoid confusion with:

- direct costs, inclusive of real cost escalations
- total costs, inclusive of direct costs, real cost escalations and shared costs (overheads).

1.2 Structure

The structure of this summary document is as follows:

Section 2 details Ergon Energy's general approach to developing the capital expenditure forecast. The aim is to provide the reader with a simple explanation of the conceptual approach taken in calculating the forecast and applying the estimated costs.

Section 3 details Ergon Energy's general approach to developing cost estimates for specified projects. The aim is to provide the reader with a simple explanation of the approach taken to estimate a project over the various phases of its lifecycle. In addition, it guides the reader to detailed information on the Ergon Energy's Estimating systems and the actual estimates used in development of its standard control services for the next regulatory control period.

Section 4 details Ergon Energy's general approach to developing cost estimates for programs of work. The aim is to provide the reader with a simple explanation of the approach taken to estimating each program. In addition it guides the reader to the actual estimates used in development of its standard control services for the next regulatory control period.

Section 5 shows the relationship between the capital expenditure categories, Ergon Energy's operational work streams responsible for the forecasts, and identifies whether the forecasts are specified investments or programs of work.

Section 6 details the specified projects that comprise Ergon Energy's regulatory submission. The aim is to provide the reader with an overview of the specified investments and the approach to developing the costs for these.

Section 7 details the programs of work that comprise Ergon Energy's regulatory submission. The aim is to provide the reader with an overview of the programs of work and the approach to developing the costs for these.

2. Methodology and approach

2.1 Objective of unit cost estimation

Investment cost estimation is part of a broader strategic approach to investment governance employed by Ergon Energy. It is a key component in the development and management of the overall network capital portfolio governance.

The approach to network capital portfolio governance aims to ensure that all capital investments for Ergon Energy are governed, developed, approved and executed in a consistent, prudent and effective manner. The objective is to ensure the safe, sustainable and timely execution of the complete capital portfolio delivering customer satisfaction and corporate value in accordance with the regulatory determination.

Cost estimating is one of three steps in cost management:

1. Cost estimating - Estimates provide the approximate cost of resources and materials to complete the projects and program investments (forecast).
2. Cost budgeting – establish the project baseline from the estimated costs – an approved budget to proceed.
3. Cost control – influence expenditure/vary costs against project budget – control variances/changes to budget.

Cost estimating, the subject of this paper, specifically supports the forecast expenditure for the next regulatory period. These cost estimates are used to develop projects and programs that are subject to relevant endorsement and approvals via Ergon Energy's governance processes. Two key aspects being:

- a review and endorsement by various committees inclusive of:
  - Network Investment Review Committee (NIRC) ($0.5m to $10m)
  - Investment Review Committee (IRC) (>$10m to $20m)
  - Board (>$20m)
- subsequent approval in accordance with the 'Ergon Energy Financial Delegation of Authority'.

Each of the investment committees, the NIRC and the IRC have charters that govern the process, the meeting and the delegation of approvals.

Refer to the 'Network Investment Review Committee (NIRC) Charter dated July 2014' and the 'Investment Review Committee Charter dated July 2014'.

The introduction of a gated methodology linked with estimate confidence and management of uncertainty is applicable to all investment activity requiring a business case across all programs of work. For further details, refer to the 'Network Portfolio Project and Program Investment Approval Governance'

2.2 Nature of unit cost estimation methodologies

Ergon Energy uses the Ellipse Enterprise Resource Planning (ERP) (See Figure 1) system to develop, monitor, analyse and review capital investments over the investment lifecycle. Ergon Energy applies two different approaches to the development of its capital expenditure forecast:

- specified investment, or specified project
- unspecified investment, or program of works

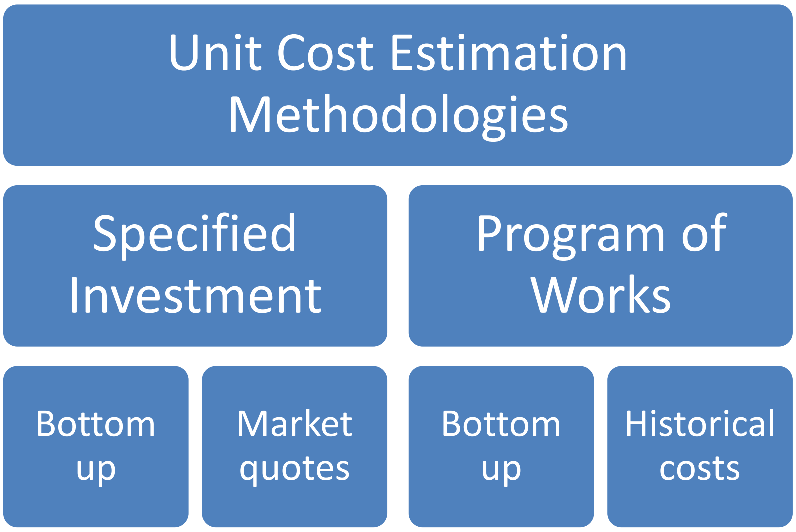

Figure 1: Components of unit cost estimation methodologies employed by Ergon Energy

The decision as to which approach is taken depends on the level of certainty of critical planning aspects. These critical planning aspects include the location and timing of the expenditure driver to develop a solution and the subsequent detailed scope.

For a specified investment, Ergon Energy develops a cost estimate for all projects in support of a business case, when there is certainty around the constraint, scope, location, and timing of the investment. The cost estimate is developed (within the Ellipse ERP) itemised via labour, materials, equipment and other resources required to deliver the project’s defined scope of work. In limited instances the cost estimate is developed outside of the Ellipse system based upon market quotations and vendor pricing. This will occur for projects such as the purchase of an IT system, or where the undertaking of a competitive tender process.

Where there is some uncertainty in the scope, location or if the investment involves significant volumes of low cost recurrent work, Ergon Energy has developed an expenditure forecast that is based on a prediction of volumes multiplied by a unit cost or program estimate. The unit cost is based on a bottom up build of costs to perform the work, or in the alternative, the estimate is derived from the cost of similar historical works performed. This type of forecast is defined as a ‘program of works’. It is generally used to provide an expenditure forecast out to seven years. Annually the consolidation of these programs will result in the production of the annual baseline forecasts to facilitate resource planning and delivery. Over the investment lifecycle and because of the gated methodology greater certainty as to cost and delivery is achieved. As such, these programs may fund new specified investments that may impact the next regulatory period. Where a specified project or sub program becomes certain during the next regulatory period then as per all new investments, they are subject to the appropriate endorsement and approval process.

For both investment types the cost estimates:

- are based on scopes of work that are verified by subject matter experts in the field that they pertain
- exclude the cost of borrowings, unknown costs, and uncertainty allowances;
- are created by estimating specialists that update the Ellipse ERP estimates when the standard designs change
- are reviewed, refined and revised as each specified investment progresses through Ergon Energy's gated governance methodology to obtain financial approval for investments
- are the most current estimate based on each project's lifecycle of development, given that Ergon Energy's specified projects may be at various lifecycle phases as at the time of this regulatory submission.

2.3 Development of unit costs within the current regulatory period

In 2011, Ergon Energy embarked on a process to improve the robustness of its network expenditure governance system. A key component of which is the estimating processes. The objective was to adopt a standardised approach to estimation across the organisation and consolidate the estimation approaches used by Ergon Energy's predecessor companies. At the completion of project implementation, the result was a comprehensive database of several hundred standard and program estimates (in the Ellipse ERP) that form the basis for specified investment and programs of works expenditure forecasts.

The estimating process in the Ellipse ERP allows the user to:

- create a job estimate from a standard estimate
- modify a job estimate to reflect refinements in design
- create a variation
- show how risk is dealt with
- stage a project phase
- package estimates
- schedule estimates
- create a major material procurement estimate (plan)
- create a requisition for major plant with long lead times

The benefits of this approach are:

- improved management of financial risk in capital works delivery
- controlled management to the annual program budget
- consistency across the organisation
- streamline estimation processes that include regular review and validation.

The costs estimates described in this document are applied to specified projects and unspecified programs to produce capital expenditure forecasts for each capital expenditure category. How this is performed is described in more detail in the 'Network Capital Expenditure Forecast Model Summary' and associated Excel model.

For the regulatory control period 2015-20, Ergon Energy has prepared its network capital expenditure forecasts based on a robust set of current and transparent unit costs. Further, it has developed business cases for each investment (specified project and program of work) to support its regulatory proposal.

3. Specified investments methodology

These investments begin with a single or combination of multiple standard estimates. Standard estimates are ready-made estimates based on standard designs and drawings, e.g. the Z6-20 Substation. The repository for these estimates is the Ellipse system, Ergon Energy's enterprise resource planning software package. A standard estimate provides a consistent and efficient basis for producing project cost estimates for works repeatedly undertaken. A standard estimate in Ellipse has an appropriate structure for estimating direct and known costs and on-costs dependent on its intended use. Standard estimates exclude the cost of borrowings, unknown costs, and uncertainty allowances. Estimating specialists create the standard estimates and update these when the standard designs change. Effectively these estimates are templates and are modified as required to accommodate the specific requirements of the investment.

There are a limited number of specified investments in Ergon Energy's regulatory submission that do not use a standard estimate. These exceptions occur when the proposed investment is unlikely to be repeatedly undertaken. An example would be a new specific project such as an IT software purchase. For these investments, the estimates are developed outside the Ellipse system and have regard for cost information including market quotations and estimates.

As a specified project progresses, it moves through five different phases of Ergon Energy's project management process.

The gated governance methodology is designed to manage uncertainties and risks associated with the project at regular intervals by building in review of proposed expenditure for prudency and efficiency at each gate as the project moves through the investment lifecycle.

Figure 2 shows the alignment of the five phases each project progresses through with Ergon Energy's gated approach for obtaining financial approval.

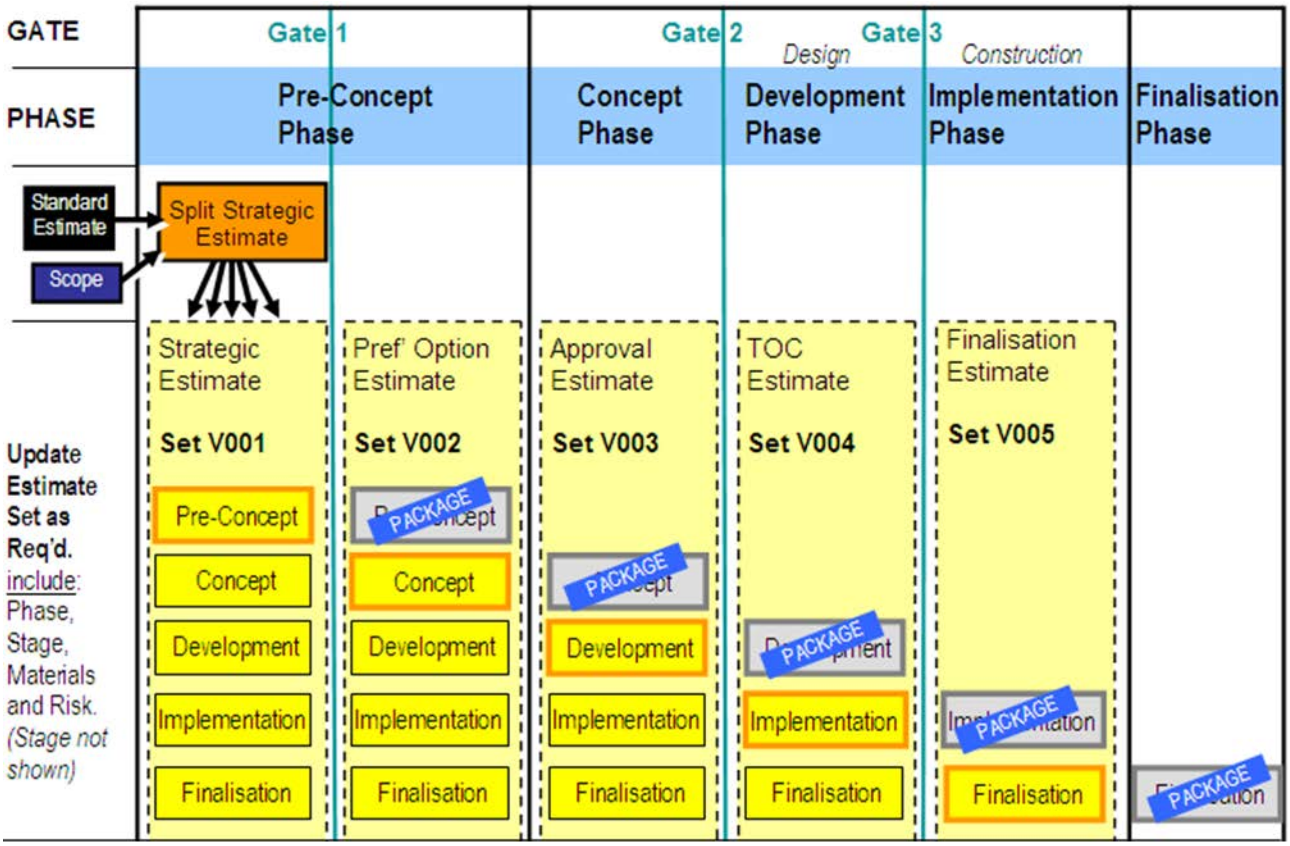

Figure 2: Source document 'About Ellipse Estimating' Version 1.8

3.1 Strategic estimates (Gate 1)

The relevant planning groups are responsible for developing strategic estimates to assess and cost options to outwork identified needs, constraints, or opportunities.

Strategic estimates exclude mobilisation costs that are normally included as the project progresses through to the concept development stage. However, preparation of Ergon Energy's regulatory submission has included an estimated mobilisation cost in all strategic estimates. Strategic estimates are suitable to develop a forecast of expenditure for three to ten years in the future and have a ±30–50% certainty.

It should be noted that in terms of approval at each gate, only the expenditure to outwork the next phase of the project is approved, to allow the scope and corresponding estimate to be re-estimated and reassessed at the next required gate.

3.2 Concept estimates (Gate 2)

The development of a concept design for the recommended option of the approved (Gate 1) business case occurs simultaneously with refinement of the estimate to align with the concept scope. These are prepared for the submission of the concept level (Gate 2) business case. Concept estimates provide sufficient business confidence for the project to further refine forecast expenditure and facilitate inclusion in resource planning and strategic logistics acquisitioning for the future two to three years. However, the exception is large projects with long-cycle times that require a longer planning period such as a new zone substation. The scope development is in sufficient detail to support an estimate that is within ±15-20% certainty.

3.3 Detail design and construct estimates (Gate 3)

If a Gate 2 business case is approved a detailed estimate is prepared to support the Gate 3 business case submission. When the business case is approved this will lead to the approval for funding to begin detailed design and construction of the project. Three avenues exist for producing detailed design estimates.

1. External detailed design and construct estimates – these are estimates with planning for external parties to deliver portions of the project. Development of the project scope will be in sufficient detail for the market to provide a schedule of rates and an estimated design cost.
2. Internal detailed design and construct estimates – these are estimates where development of the scope of the project is in sufficient detail for the business to develop, with confidence, a detailed design and construct estimate. A scope of work supports the detailed design and construct estimate. This uses the Gate 2 estimate as a starting point, adding or refining items, and costs to account for the proposed investment's specific risks, issues, and project delivery.
3. Market estimates – these are estimates where development of the scope of the project is in sufficient detail with the appropriate confidence for the market to provide a quoted lump sum design cost.

For all avenues above, the development of the scope is in sufficient detail to constitute a detailed design estimate to provide an estimate with ±10% certainty.

Annual updating of estimates for variations in labour rates, and material costs upon renewal of material procurement contracts, further support the robustness of Ergon Energy's gated governance estimating process.

3.4 Application of uplift costs to specified investments

Generally, specified project estimates do not have uplift costs applied as these projects are inclusive of all costs. For further detailed information on the estimating and investment governance process that Ergon Energy applies to its specified projects, see the following documentation:

- 'About Ellipse Estimating', V1.8, January 2014
- 'Network Portfolio Project and Program Investment Approval Governance',V2.0 (Gated methodology)
- 'Network Investment Review Committee (NIRC) Charter' dated July 2014
- 'Investment Review Committee Charter' dated July 2014
- 'Ergon Energy's Financial Delegation of Authority'

For a detailed list of the specified projects, inclusive of preparation details and corresponding estimated cost, for the regulatory control period 2015-20, please refer to Section 5.

Given that Ergon Energy's specified projects may be at various life-cycle phases, the estimates used in its regulatory submission are the most current estimates based on each project's lifecycle of development.

4. Program of work investments methodology

Ergon Energy adopts a program-of-works planning approach where a business problem or response is not clearly specified. Programs of work applies to high volume/low cost repeatable investments or where there is some uncertainty owing to a reliance of inspections not yet conducted, short notification times, unknown scope or unknown location of works into the future.

The basis for the forecast expenditure for each program is a prediction of volumes (which may be based on, for example, historical volumes) multiplied by unit cost(s). This unit cost is an estimate of cost based on a combination of approaches and defined as a program (cost) estimate.

The approach taken to develop each program estimate depends on the availability, comparability, and granularity of historical data and is either:

- Historic average cost program estimates
- Bottom up program estimates

Where there is correlation of the forecasted activity to historical activity, then an averaging of recorded costs provides the basis of Ergon Energy's program estimates. Where there are no comparable historical costs to draw on, Ergon Energy has built its program estimates based on a typical scope of work reflective of the future activity and compared this to a sample of recorded cost data (such as a pilot program or a one-off event) or a comparable component of a standard estimate.

This section aims to give the reader an understanding of how Ergon Energy developed its program estimates for its regulatory submission.

4.1 Historic average cost program estimates

Development of some program estimates uses an average of recorded historical costs. This is the case when the expectation is that future activities and costs will reflect the historical activities and associated costs, e.g. cost to connect a domestic customer. These costs include all direct costs related to the investment such as labour, materials, equipment, mobilisation and contractors' costs.

The average of these historical costs over multiple years provides a robust estimate of future costs for Ergon Energy's program estimates and expenditure forecast.

4.2 Bottom-up program estimates

Development of bottom-up program (or product) estimates follows where historical data is unavailable or where data is not reflective of future activities or costs. This approach uses a planning scope of work that reflects future activity. Specialist estimators use the scopes to estimate an efficient unit cost that represents the cost to do the task only and is exclusive of mobilisation (travel time and accommodation costs), contractor uplift and contingency.

Depending on the type of work planned for each program and historical cost information available, the assessment of unit costs against at least one of the following sources validates the robustness of each estimate:

- one-off project or program historic actual costs
- proven estimates
- market costs
- market estimates/quotations
- the expert knowledge of Ergon Energy's subject matter experts. (SMEs) (peer review).

4.3 Application of uplift costs to program of work investments

Unlike historical average cost estimates, bottom-up program estimates are based on direct internal costs (typically labour and materials) required to perform only the intended activity that does not include:

- any cost allocation for mobilisation costs to site (for both labour and materials where applicable)
- the use of external contractors.

As such, Ergon Energy developed and applies two different cost-uplift factors, where required to reflect the entire direct cost of the work.

4.3.1 External contractor uplift

Ergon Energy's use of a contractor uplift component, over and above the program estimates it is appropriate to account for:

- contractor profit margin
- differences in the costing mechanism for overhead costs attributable to the direct cost of work, e.g. training, safety equipment, non-chargeable time etc. Specifically:
  - external delivery – contract resourcing recovers overhead via inclusion in rates
  - internal delivery – Ergon Energy recovers overheads via the allocation process in the Corporate Allocation Model, and therefore is excluded from the program estimates.

To establish the percentage contractor uplift a review of a sample of completed projects over 4.5 years (from July 2008 to December 2012) provides a reasonable reflection of the contractor uplift. The analysis provides the direct actual cost extracted from Ellipse, for 6,299 completed projects that includes internally and externally delivered projects.

Step 1: Determine the magnitude of work outsourced

Simple analysis of the outsourced component of the work indicates that 12% of the works was delivered using external resources.

Step 2: Develop the cost uplift for work outsourced

To create an unbiased comparison of works delivered internally, versus externally, from the sample-required identification of the direct unit cost for labour, equipment, material, and other costs. The unit cost for the material component, for both internal and external, provides a suitable reference to identify the magnitude of the works delivered for each project.

The outcome indicates that the average total cost of those projects delivered by external resources were approximately 3.53 times the cost of work delivered by internal resources. Additionally the projects delivered by external resources are 3.23 times larger than the work delivered by internal resources.

This equates to a contractor cost uplift for external delivery of 9.2% (=3.53/3.23).

Step 3: Develop an external contractor uplift applicable to a program

Thus, the external contractor uplift Ergon Energy applies to its program estimates (bottom-up) is 1.1%, which is based on the estimation of the historical contractor cost uplift incurred (9.2%) multiplied by the percentage of work forecast to be outsourced (12%).

Table 1 shows the percentage contractor uplift applied to each of Ergon Energy's network capital expenditure programs by work stream.

4.3.2 Mobilisation uplift

Mobilisation costs relate to the cost for travel, transport and accommodation associated with each program. As stated above, bottom-up program estimates do not include any costs for mobilisation. The geographic location of the components of the network and the workforce mobilisation to these locations are key cost drivers in completion of the estimated tasks. Thus, using the bottom-up program estimate approach Ergon Energy prudently applies various mobilisation uplift factors owing to the varying travel requirements of each program. For example:

- the defect remediation program and replacement metering program involves more travel time for personnel in between performing short repetitive tasks (being the basis of the program estimate) at multiple locations dispersed across vast areas of the network
- conversely, tasks associated with other programs are typically focused on a single location such as a feeder or substation that consequently results in less inter-task travel and a lower mobilisation uplift.

Derivation of mobilisation costs for each program is achieved by obtaining historical data of completed works that had similar travel requirements for each program being forecast and:

- analysing the transport, travel or accommodation cost elements as a proportion of total direct cost (exclusive of mobilisation). For Line Maintenance this also includes supervision costs. Refer to the 'Line Asset Defect Management Methodology'.
- compared the bottom up program estimate against a proven historical estimate that included all costs to derive the required mobilisation uplift.

It should be noted that as the identified network need becomes more certain over time, some programs of work will transform into multiple specified investments and be governed via Ergon Energy's gated governance methodology for obtaining financial approval. It is an Ergon Energy requirement that this governance framework is applied to all specified investments for financial consideration and approval.

Table 1 shows the percentage mobilisation uplift applied for each of Ergon Energy's network capital expenditure programs by work stream.

Table 1: Mobilisation factor and external resource contract uplift

Ergon Energy work stream	Cost uplift	Percentage uplift
Sub transmission Augmentation	Mobilisation	Not applicable
	Contractor	Not applicable
Distribution Augmentation – Modelled	Mobilisation	9.81
	Contractor	1.1
Distribution Augmentation – Un-modelled	Mobilisation	Not applicable
	Contractor	Not applicable
Network Refurbishment	Mobilisation	11.1
	Contractor	1.1
Line Maintenance	Mobilisation	52.6
	Contractor	1.1
CICW	Mobilisation	Not applicable
	Contractor	Not applicable
Operational Technology	Mobilisation	9.98 – 11.1
	Contractor	1.1
Metering (only end-of-life replacement of meters/non-compliant meter family)	Mobilisation	40.42
	Contractor	1.1
Telecommunications	Mobilisation	4.99
	Contractor	1.1
Reliability Improvement	Mobilisation	10.63
	Contractor	1.1
Power Quality	Mobilisation	12.66
	Contractor	Not applicable

4.4 Detailed information

Section 7 of this document shows Ergon Energy's program estimates/unit costs that support its regulatory submission.

5. Summary of network capital expenditure categories

As can be seen in Table 2, there is not a one-to-one relationship between the capital expenditure categories and Ergon Energy's operational work streams, as some work streams' forecasts relate to multiple categories. Similarly, as discussed in section 4.3.2, work streams forecasts can relate to both Programs and Specified investments.

Table 2: Ergon Energy's network capital expenditure categories

Category	Work stream	Forecasting sub-category		Forecast approach P=Program S=Specified
Customer Initiated Capital Works	Customer Initiated Capital Works	Commercial and Industrial		P
		Domestic and Rural		P
		Subdivisions		P
		Large Customers		P
		Street Lighting		P
		Metering		P
		Services		P
Augmentation	Sub-transmission Augmentation	Northern		S
		Central		S
		Southern		S
	Distribution Augmentation	Northern	Reactive (Un-modelled)	P
			Modelled	P and S
			Photovoltaic related augmentation	P
		Central	Reactive (Un-modelled)	P
			Modelled	P and S
			Photovoltaic related augmentation	P
		Southern	Reactive (Un-modelled)	P
			Modelled	P and S
			Photovoltaic related augmentation	P

Category	Work stream	Forecasting sub-category	Forecast approach P=Program S=Specified
Asset Renewal	Line Maintenance	Defect Management	P
		Ring Main Unit (RMU) replacement	P
		Distribution Earthing remediation	P
		Connector splice replacement	P
		Figure 8 colour coded service replacement	P
		Overhead customer connections inspection and replacement	P
		Neutral screened service cables	P
		Cast iron pot head replacement	P
		Laminated cross-arm replacement	P
		Non-ceramic customer end service fuse replacement	P
		Expulsion Drop Out (EDO) fuse replacement in high risk areas	P
		Site access repair	P
		Minor tasks	P
		Wood pole nail	P
		Wood pole repair	P
		Wood pole replace	P
		Steel pole replace	P
		Post Natural Disaster Defect Remediation	P
		Major Items Failed in Service (MIFIS)	P
Asset Renewal	Metering	Replace metering end-of life	P
		Replace metering in-situ	P
		Replace metering obsolete	P
	Public Lighting	Bulk Lamp Capital Replacement Program	P
	Network Replacement	Sub transmission line refurbishment	P
		Substation power transformer replacement	P
		Distribution feeder re-conductoring	P
		Instrument transformer replacement	P

Category	Work stream	Forecasting sub-category	Forecast approach P=Program S=Specified
		Substation (High Voltage) HV circuit breaker and switchboard replacement	P
		Substation isolators replacement	P
		Substation DC system upgrade	P
		Substation Static VAR Compensator replacement	P
		Substation Capacitor Bank replacement	P
		Protection relay replacement	P
	Operational Technology	Audio Frequency Load Control (AFLC) equipment asset replacement	P
		RTU replacement	P
	Telecommunications	CoreNet, Site Infrastructure Replacement	P
		End-of-life Radio Refurbishment	S
Reliability and Power Quality	Reliability	Worst Performing Feeders	P
	Power Quality	Power Quality Monitors	P
		Power Quality Analysers	P
Other System and Enabling Technology	Network Replacement	Substation power transformer bunds	P and S
		Low Voltage spreader and fuse	P
		Substation AC system upgrade	P
	Operational Technology	Distribution Management System (DMS) system	S
		Protection review	P
		Integrated Network Operations Centre - Intelligent Electronic Device Monitoring and Support	S
		Master Station	S
		Regulator Remote Communications Strategy	P
		Operational network security	S
		Sensitive Earth Fault (SEF) protection	P
		Alternative Data Acquisition Service (ADAS)	S
	Metering	Metering configuration management	S

6. Specified investments

Ergon Energy has prepared specified project estimates to support its regulatory submission in the following section.

The following tables show the relative costs for each specified investments by work stream that supports Ergon Energy's regulatory submission.

All costs shown are total direct costs (exclusive of overheads and other indirect costs).

6.1 Sub transmission and Distribution Augmentation

The basis for the breakdown of the work for this stream is Ergon Energy's geographic regions:

- Northern
- Central
- Southern

These regions, largely separate and discrete, are the legacy regions merged to create the Ergon Energy network.

Unit cost estimation table

Table 3 summarises the cost-estimation approach for Sub transmission and Distribution Augmentation.

Table 3: Sub transmission and Distribution Augmentation cost estimation

Work stream	Unit of measure	Approach to costing	Cost elements
Sub transmission and Distribution Augmentation	Individual project to meet an identified constraint	Standard, strategic, concept or detailed estimates applied to each specific project	Labour Materials Equipment

The sub transmission augmentation category comprises of specified projects (see Table 4) and investments required for the sub transmission network. As each constraint is different and potentially addresses more than one issue in an identified geographic region, each project is different in its size and nature. A single project or a group of projects, depending on its nature, may address multiple constraints. This is focused around efficiency in delivery.

The distribution augmentation category forecast consists of both a list of specified projects (see Table 5) and a single program for each of Ergon Energy's major operational regions being, Northern, Central and Southern. The distribution specified investments have individual business cases, which represent the work that is either under construction (in the current period only) or in the short term 1-2 year planning window required for the distribution network that requires financial approval, resource planning, and/or procurement. Each constraint is identified at a feeder level. Both categories utilise either a standard, strategic, concept or detailed estimates applied to each specific project. For further details on augmentation investments, see the 'Forecast Expenditure Summary Corporation Initiated Augmentation 2015 to 2020'.

Sub transmission and Distribution specified investment cost table

Table 4: Sub transmission Augmentation and Table 5 identify the cash flow over the regulatory control period 2015-20 relating to all specified project expenditure for sub transmission and distribution augmentation respectively.

Table 4: Sub transmission Augmentation

	Work request # /Ellipse estimate code	Investment description	Direct cost ($ real 2012-13)
1	436900	FNC Smithfield 132/2 ZS Site Use Approvals Ministerial Designation	48,000
2	733880	Edmonton-Install two new 22kV feeder bays	197,806
3	168182	Bowen sub 2 x 11kV Feeder Bays Install additional 2 x 11kV feeder CB	124,338
4	443784	Cloncurry 66 kV Reinforcement Install 2nd DURO 11/66 TF	165,261
5	CPMNN01145	Blackwater to Emerald 66kV Line Rebuild with DCCP Line	10,000,000
6	317031	Substation, Gracemere, Modular, 66/11kV, Network, Central	10,866,667
7	693294	Briffney Establish new 66/11kV Sub Establish Briffney zone substation	11,485,118
8	48821	Substation, Moranbah Town, Modular ,66/11kV,32MVA, network Central	6,609,399
9	48824	Substation, Moranbah, Refurb, 66kV, 32MVA, Network, Central	5,730,874
10	DCP18260	Line, Glenella to Planella, New Standard, 66kV, Network, Central	3,209,720
11	48598	Planella – Convert to 66/11kV Design and re-construct	3,313,258
12	DCP16183	Glenella – Install 66kV feeder bays Install 2 x 66kV feeder bays for Planella	1,250,831
13	311743	Boyne Res redevelop switchyard & augment TF Install 66kV bays & larger TFs	3,667,957
14	154826	Cannonvale Sub 66kV switch-yard Cannonvale 66kV Switch/Yard	5,000,000
15	CPMNN01466	Gladstone South Sub – Install 2x20MVA Transformers and Replace 11kV	2,500,000
16	444030	Calliope 66kV Reinforcement Install 66kV bay & connect Beecher line	627,423
17	48238	Mackay Harbour ZS Site Acquisition Investigate & Acquire ZS	476,216
18	832068	Baralaba Central/South Mine Develop SCS Cockatoo Coal Limited	80,169
19	782822	RCA MK AST Line Route Planella Bucasia	117,286
20	830023	Tannum Sands 11kV Easement Compensation	75
21	140507	Substation, Central Toowoomba, Greenfield, 110/11kV, Network, SWest	1,046,004
22	140221	Line, South Toowoomba Sub to Central Toowoomba Sub, 10kV, SW.	8,594
23	DCP17784	RSW TO ASC CHAL TX New CHAR 33/11kV ZSS at Charlton	9,263,215
24	183596	SPD WB AT ISIS T131 OH New to GAYNDAH	41,500,094

	Work request # /Ellipse estimate code	Investment description	Direct cost ($ real 2012-13)
25	306794	T131 Isis new 66kV feeder bay to connect new Isis-Dallarnil line	2,376,494
26	141629	Kumbia 66/11kV ZS Establishment Establish Kumbia 66/11kV ZS	4,997,014
27	432340	Kingaroy ZS – Install new 66kV feeder bay For proposed Kumbia feeder	3,704,241
28	431150	Kumbia Feeder – Re-energise at 66kV feeder bay at Kingaroy	523,556
29	316573	Broxburn Sub Rebuild as 110/11kV	1,591,000
30	196710	ConstrDCCP – Toogoom 66/11kV ZS Construct DCCP Ln from HWP	1,630,508
31	196687	Toogoom – Establish 66/11kV ZS ZS6-20 Zone Sub at Toogoom Site	5,450,000
32	419495	Roma W 33/11kV TF & 11kV Switch gear Aug Replace external TFs & 11kv	1,555,822
33	132601	Refurb 33KV bus TRG SAGT refurbishment 33kV bus –TRGP-M13.1	459,131
34	284072	Property, Postman's Ridge to North Street, Line, Acquisition, South West	1,636,940
35	473915	Property, Wandoan, Line, Acquisition, South West	610,667
36	CPMNS00402	Augment 110/33kV TX at T013 Chinchilla	161,582
37	316490	West Warwick Sub11kV Feeder bay install additional CB on 11kV switchboard	84,633
38	455124	Childers To Givelda Ln Route Investigate existing Ln and confirm	32,286
39	448012	T20 Bundaberg-South Bberg 2nd 66kV line Extend off T20-T131 66kV feeder	10,944
40	50685	Establish Avoca 66/11kV Zone Substation Establish a new ZS at Avoca	4,300,000
41	616381	Edmonton South ZS site acquisition	1,112,391
42	47822	G-vale – Mt Peter 132/22kV ZS Site Property Acquisition	483,217
43	168194	Garbutt 66kV Reinforcement Install 66kV bay to connect Powerlinks	929,184
44	733325	66kV Mareeba Feeder Rating Increase max operating temp to 65C	18,429
45	826494	Guthalungra TF Augmentation Replace existing TF with 1.5MVA unit	479,389
46	552296	Dysart 66/22kV TFs Install 20MVA 66/22kV TFs	10,000,000
47	760213	Dysart 66kV TF Bay install 66kV TF bay for Powerlink 3rd TF	500,000
48	48638	Substation, Ooralea, Modular, Network, Mackay	5,290,805
49	48647	Ooralea SCCP 66kV Line Construction Design and construct	739,000
50	653444	Racecourse Mill – Install 66kV feeder bay	2,560,000
51	626232	Kingaroy – Install one 5MVAr cap bank	653,265
52	901276	St. George Supply Reinforcement	4,791,000

	Work request # /Ellipse estimate code	Investment description	Direct cost ($ real 2012-13)
53	901533	Charleville Supply Reinforcement	9,317,000

Table 5: Distribution Augmentation

	Work Request # /Ellipse estimate code	Investment description	Direct cost (real $ 2012-13)
1	328901	NOTV DPN BOHL 11kV Feeder Exit Augment Upgrade BO-4 & BO-10 Cables	324,795
2	733323	FNT MOSS 2DAI Bamboo Ck Tie Construct tie Whyanbeel – Bamboo Ck	66,578
3	737891	FN, Cardwell 132/22 kV,Auquaculture,22kV Extend Aquaculture feeder	404,720
4	752865	NO COL ZSB 66/11CO-02 Isolate Uniso SWER Isolate	891,458
5	DCP17911	FN,Innisfail 132-22kV,Babinda 1,2BA1,22kAug works 2BAT and 2BAM	1,131,479
6	327664	CA DP New Regulator LONG Longreach Isisford FDR	118,968
7	328282	CA DP New Regulator Stanwell FDR MALC Malchi	134,727
8	328323	Line, Briffney, New, 11kV, Network, Capricornia	2,717,689
9	328478	Line, Gracemere Sub Feeder Exits, 11kV, Network, Capricornia	2,432,052
10	328508	CA DP BRIF New ZS FDR Exits-STG2	1,042,481
11	328578	MK DP JUPO Waterson Way New Feeder	1,604,042
12	328642	Line, Moranbah, New Standard, 11kV, Network, Central	2,242,096
13	329385	CA DP PAND Glendale SS Establishment	1,224,867
14	640084	CA DP BORE Feeder Exit Upgrades Tannum Sands and Tarcoola FDRs	12,731
15	642039	CA DP BORE Industrial FDR Tie	144,046
16	740739	CA DP MONT Moonford FDR Regulation	35,467
17	742562	Lines, Ooralea, Lines New, Network, 11kV Feeders, Mackay	3,634,762
18	168413	RSW SW TO DSA KESP 3 x Feeders New Est 3 new distribution feeders out of KESP	1,192,921
19	171761	RSW SW TO DSA CETO OH New distribution 11kV distribution sys out of rebld Tmb Cen	11,341
20	171773	Line, Charlton Sub Dist Feeders, 11kV, Network, South West	2,117,735
21	171781	Broxburn Sub rebuild – Distribution Work Establish new feeder & reconfigure	480,904
22	172681	RSW SW TO DSA CEPL FIP ASCR Cond Reconstruct OH to 75deg C	340,197
23	335974	WB DP, ROST, create four new feeders and reconfigure exiting feeders	1,928,124

	Work Request # /Ellipse estimate code	Investment description	Direct cost (real $ 2012-13)
24	336062	WB DP, BARG, create four new feeders	1,819,440
25	336399	WB DP, TOGM, create five new feeder from new ZS re-arrange network	3,753,440
26	336410	WB DP, AVOCA, establish new feeders from new ZS re-arrange network	4,913,399
27	336962	WB DP, YARR, Blackbutt, new reg	53,486
28	337087	WB DP, PIAL, Distribution Work Stage 1	2,287,126
29	337091	WB DP, PIAL, Distribution Works Stage 2	1,064,727
30	337213	WB DP, Kumbia, create four new feeders new ZS re-arrange existing network	1,487,796
31	337387	WB DP, WALL, Gin Gin upgrade UG cable Gin Gin	23,434
32	337408	WB DP, NANA, Brooklands feeder reconductor first 1.6km of 0.80 CU	189,316
33	552376	RSW TO CR WEET St11 Cu Cond Replace Grenwa & Tomkinson St	37,788
34	DCP15397	WB DP,OWAN,Bidwill,OY-B,11kV augment, Erect Voltage regulator	8,584
35	DCP15456	WB DP,NANA ,South Nanango,NN-E,11kV augment Reconductor Temp	153,533
36	DCP15486	WB DP,WALL ,Drinan,WV-D,11kV augment, Increase Design Temp of 3.7 km	211,226
37	DCP15673	SW,Allora (ME037),Hendon,F3085,11kV augment Voltage regulation and tie	209,512
38	DCP15703	SW, Charleville (MW007),Morven,F3605,22kVVoltage regulator 22kV	143,063
39	DCP15710	SW,Millmerran (ME151),Bringalily,F2295,1Erect a VR in PE4912	144,019
40	DCP15735	SW,St. George Town (MC053),Alfred St Ea. Reconductor approx. 1.5km	288,121
41	DCP15772	SW,Crows Nest (ME032),Creek St,F2645,11kReconductor initial feeder	399,018
42	DCP16904	WB DP,KING,Coolabunia,KR-D,11kV augment, Reconductor 5km of feeder	251,135

6.2 Operational Technology

This work stream consists of the following specified investments:

- Implement Distribution Management System (DMS)
- Operational Network (cyber) Security
- Alternative Data Acquisition Service
- Integrated Network Operations Centre
- Master Station SCADA Strategy
- Regulatory Remote Communications Strategy

Cost estimation summary table

Table 6 summarises the Operational Technology's cost-estimation approach.

Table 6: Operational Technology's cost estimation

Work stream	Unit of measure	Approach to costing	Cost elements
Implement Distribution Management System	Individual project	Bottom-up estimate of each component: • Hardware, software, implementation • Internal labour – standard labour rates	Labour Materials
Operational Network (cyber) Security	Individual project based on vendor pricing tool and estimated labour hours	The estimate derived by summing the individual assets installation costs and labour hours, is inclusive of all costs except corporate overheads	Labour Materials
Alternative Data Acquisition Service (ADAS)	Individual project based on vendor pricing and estimated labour hours	The estimates include asset-installation costs and labour hours, and are inclusive of all costs except corporate overheads	Labour Materials
Integrated Network Operations Centre	Individual project	Cost estimates for the software component were based on previous experience and costs obtained from recent related upgrade costs at the Communications Network Operations Centre. This included licenses and professional services for the NMS from the recent IBM and deploy partners proposals	Labour Materials
Master Station – SCADA Strategy	Individual project	Cost estimates for labour use standard labour rates applied to the estimate of hours required. Materials costs are based on the costs recorded in Ellipse for previous projects. Software costs are based on vendor quotes from a supplier. These costs are inclusive of transport and accommodation	Labour Materials

Implement Distribution Management System (DMS)

The Distribution Management System is a decision-support system that assists the control room and field operating personnel to monitor and control the network in an optimal manner, while enhancing safety and asset protection.

Approach to costing the investment

As this is a one-off project and not a recurrent activity, the development of this project estimate is outside of the standard estimate framework. Developing the investment costs has the following phases:

- contract for the next regulatory control period completed in the current 2010-15 regulatory control period
- blueprint design for the next regulatory control period completed in the current 2010-15 regulatory control period
- installation of Distribution Management System, to commence in the 2010-15 regulatory control period and finalised in the 2015-20 regulatory control period
- integration with corporate systems to commence in the 2010-15 regulatory control period and finalised in the 2015-20 regulatory control period.

The costs for installation of the Distribution Management System phase consist of three components:

- hardware, software and implementation
- internal labour
- travel.

The hardware, software, and implementation costs use a tender price from suppliers.

The internal labour costs use standard labour rates applied to the estimate of hours based on the expert knowledge of Ergon Energy's SMEs.

The costs for the integration with corporate systems phase consist of two components:

- implementation
- internal labour.

The implementation costs are based on a tender price from the supplier/contractor.

The labour costs use standard labour rates applied to the estimate of hours as based on the expert knowledge of Ergon Energy's SMEs.

The estimate developed to support Ergon Energy's submission is a summation of the above costs. These costs are inclusive of travel and accommodation. Building the costs uses a bottom-up approach for a total cost-of-ownership model used in the tender evaluation.

Energex's recently completed Distribution Management System project has enabled the opportunity to benchmark components of the implementation where relevant.

Operational network (cyber) security

This project is driven by an external consultancy review conducted in 2010 that identified risks associated with Ergon Energy's current practices in comparison with the United States industry best-practice model. Ergon Energy's risk framework supports actions to control potential intrusions, which possibly result in serious consequences.

Approach to costing the investment

As this is a non-recurrent one-off project, development of the estimate for this project occurred outside of the standard estimate framework.

Costing of individual assets used a vendor-pricing tool provided by SPARQ solutions, using a mid-level cost from the market tender where an item was not available in this tool.

SPARQ solutions and Ergon Energy's SMEs estimated the labour hours for implementing each component applying standard labour rates.

Summing the individual assets installation costs and labour hours produced the investment cost that is inclusive of all direct costs.

Alternative Data Acquisition Service

Ergon Energy, as part of its corporate strategy, needs to prepare for the 'network of the future'. This is a network where we expect multidirectional flows of information and power. To manage this network, the business will need to collect more information from zone substations as well as extending monitoring and control capability to the medium voltage to low voltage (LV) networks.

Owing to its critical nature, using the existing SCADA system to manage this data will incur significant cost to the business to expand. It is also important that the business does not overload or clutter the system, placing the network at risk of performance issues that may compromise remote control of the HV network. Due to not having this centralised system, the business has started to use vendor web services or data collection software provided by device manufacturers. Additionally the business also manually collects and downloads data locally or remotely over Ergon Energy's Operational Communications Network.

Without an Alternative Data Acquisition Service (ADAS), the business will continue to implement these types of independent and inefficient solutions, which consequently makes it difficult for the wider business to access data, may place data at the risk of being lost, and will require individual maintenance at a higher cost to the business.

Approach to costing the investment

As this is a one-off project and not a recurrent activity, the development of this project estimates is outside of the standard estimate framework.

The bottom-up estimate consists of two components:

- hardware and software
- implementation

The basis for hardware and software costs is indicative pricing provided by software vendors in the current trial.

Standard labour rates and an estimate of hours required to undertake the work by Ergon Energy's SMEs provide the implementation costs.

The data-collection gateway and the historian database are the two main components of the estimate. Estimation of the gateway software for data collection is on a per-device basis, while estimating for the historian software was per data point (as per pricing structure of historian vendors). The point estimate per device used was 35 points per device.

As this is a new system, validation against similar projects is difficult. Ergon Energy also found that costs are non-comparable with Ausgrid, who structured its ADAS trials with government funding.

The system proposed is an off-the-shelf system for industrial applications, so the cost proposed by the vendors is the market price.

There are no anticipated transport and accommodation costs associated with this project, therefore the estimate does not include these costs.

Integrated Network Operations Centre

This proposed investment seeks funding to extend the functionality of the Communications Network Operation Centre to manage the increase in intelligent electronic device implementation throughout the network as standard equipment or performing discrete functions.

The monitoring of active-device assets will assist in bedding in and maintaining the efficiencies these devices have to offer and ensure that they are functioning correctly, and available to perform now and into the future.

Approach to costing the investment

As this is a one-off project and not a recurrent activity, the development of this project estimate is outside of the standard estimate framework.

The scope of the investments over the regulatory control period provided the basis for estimating these costs.

The Integrated Network Operations Centre costs consist of a software component, based on previous experience and costs obtained from recent related upgrade costs at the Communications Network Operations Centre. This included licenses and professional services for the network monitoring system as an outcome of the recent IBM and deploy partners proposals.

Master Station Supervisory Control and Data Acquisition System (SCADA) Strategy

This project outworks the, the Master Station SCADA strategy for hardware replacement/expansion, software and licence upgrades. It is necessary for the Operational Control Centre to perform its daily duties, as well as providing Ergon Energy with critical asset data.

Approach to costing the investment

As this is a one-off project and not a recurrent activity, the development of this project estimate is outside of the standard estimate framework. The costs consist of four components:

- labour hours
- materials
- software
- hardware

The labour costs use standard labour rates applied to the estimate of hours based on the expert knowledge of Ergon Energy's SMEs and the labour required for previous upgrade projects.

The materials costs are based on the costs recorded in Ellipse for previous projects.

The software costs are based on vendor quotes from the supplier and SME's experience in delivering previous upgrade projects since the implementation of the Master Station in 2008.

These costs are inclusive of transport and accommodation.

Operational Technology specified investment cost table

Table 7 identifies the specified project expenditure forecast in direct cost.

Table 7: Operational Technology

	Work request # /Ellipse estimate code	Investment description	Direct cost ($ real 2012-13)
1	578093	Distribution Management System (DMS)	13,041,865
2	MIP1095	Operational network cyber security	4,562,000
3	MIP1163	Alternative Data Acquisition Service (ADAS)	4,007,698
4	MIP1164	Integrated Network Operations Centre - Intelligent Electronic Device Monitoring and Support	1,681,360
5	MIP1263 to MIP1267	Master Station SCADA Strategy	13,148,147

Note: For all specified investments that have an estimate created outside the estimating framework, special unitised cost estimates were developed to reflect the labour, materials, equipment, contractors and other costs associated with each investment. These unitised cost estimates were then multiplied by the derived annual volumes such that the product of the two equated to the total direct annual cost requirements estimated by the work stream(s) in their source models and forecasts. Importantly, this was undertaken only as a mechanism to load the annual labour resource requirements associated with each specified investment into Ellipse, for inclusion in the development of the Network Deliverability Plan.

6.3 Telecommunications

This work stream consists of the following two specified investments:

- End-of-life radio refurbishment Mackay to Maryborough
- End-of-life radio refurbishment Western Queensland

The radio communications systems are out of date and no maintenance support is available for this technology. To maintain field communications for staff, replacement systems are required.

Cost estimation summary table

Table 8 summarises telecommunications cost-estimation approach.

Table 8: Telecommunications cost estimation

Work stream	Unit of measure	Approach to costing the program	Cost elements
Telecommunications End-of-life radio refurbishment Mackay to Maryborough and Western Queensland	Individual projects	Unit rates were determined from existing commercially obtained contractor rates for similar projects located in inner South-West Queensland and Far North Queensland areas	Labour Materials

Approach to costing the investment

Owing to the asset types not having standard estimates, the development of these project estimates is created outside of the standard estimate framework.

The scope of the investments delivered over the regulatory control period provided the basis for estimating these costs.

The end-of-life radio refurbishment costs are derived from commercial arrangements established for similar projects located in the inner South-West Queensland and Far North Queensland areas.

Telecommunications specified investment cost table

Table 9 identifies the specified project expenditure forecast in direct cost

Table 9: Telecommunications

	Work request # / Ellipse estimate code	Investment description	Direct cost ($ real 2012-13)
1	MIP1171	End-of-life radio refurbishment Mackay to Maryborough	15,486,076
2	MIP1171	End-of-life Radio refurbishment Western Queensland	12,411,738

Note: For all specified investments that have an estimate created outside the estimating framework, special unitised cost estimates were developed to reflect the labour, materials, equipment, contractors and other costs associated with each investment. These unitised cost estimates were then multiplied by the derived annual volumes, such that the product of the two equated to the total direct annual cost requirements estimated by the work stream(s) in their source models and forecasts. Importantly, this was undertaken only as a mechanism to load the annual labour resource requirements associated with each specified investment into Ellipse, for inclusion in the development of the Network Deliverability Plan.

6.4 Metering

This work stream consists of a single specified investment, split evenly between SCS and ACS:

- Metering configuration management

Cost estimation summary table

Table 10 summarises metering cost estimation approach

Table 10: Metering cost estimation

Sub-program	Unit of measure	Description of unit	Approach to costing the sub-program	Cost elements
Metering configuration management	Hand Held Units (HHU)	Bottom-up estimate of costs based on current purchasing cost for each unit: • HHU • Probe	Estimates applied to each new asset to determine a sub-program cost	Labour Materials

Metering configuration management

The purpose of the project is to enable programming of electronic meters and ripple receivers installed in the field as opposed to physically replacing metering assets to accommodate customer requests in changes to tariffs. This will lead to a cost saving by extending the asset life of the installed electronic metering asset (meters & external ripple receivers) in the field and also saves on time required to accommodate the tariff change requests.

Approach to costing the investment

The estimate for this project is based on the cost to purchase the necessary equipment and the cost to support their integration.

The bottom-up cost estimates consist of five components:

- hand held units
- back office software
- processes and procedures
- program support
- program management.

The hand held units estimate is based on the current purchase price of the units for meter reading on the current IT list, provided by SPARQ solutions, plus the cost for the probe.

The back office software estimate is based on the estimate provided by SPARQ solutions, taking into account the significant amount of integration required to ensure compliance and maximum benefit.

The Processes and procedures estimate is based on standard labour rates and an estimate of hours required by Ergon Energy's SMEs.

The program support and program management estimates are based on the percentage of the total costs of the Wide Bay region metering asset replacements, currently being undertaken. Whereby training is required, mobilisation costs have been included in the program as support cost.

Metering specified investment cost table

Table 11 identifies the specified project expenditure forecast in direct cost.

Table 11: Metering

	Work request # / Ellipse estimate code	Investment description	Direct cost ($ real 2012-13)
1	MIP1158	Configuration Management (SCS & ACS)	5,411,721

7. Program estimates

Ergon Energy has prepared program estimates to support its regulatory submission in the following works streams.

The following tables show the relative costs for each program estimate that supports Ergon Energy's regulatory submission.

All costs shown are total direct costs (exclusive of overheads and other indirect costs).

The product of these estimates and the corresponding forecast volumes produce the total expenditure in direct cost (2012-13 real dollars) for each program.

7.1 Distribution and Low Voltage Augmentation

This program has the following structure of sub-programs:

- Southern
  - Un-modelled
  - Modelled
- Central
  - Un-modelled
  - Modelled
- Northern
  - Un-modelled
  - Modelled

The geographical areas of operation formulate the program structure. These geographical areas represent the legacy regions that merged to create the Ergon Energy network, are largely separate and discrete.

Each area is further broken down into sub categories modelled and un-modelled. Modelled works consist of identified as constraints at specific feeders and locations via load-flow modelling the growth of the network and un-modelled works is reactive work usually initiated by a network issue or customer complaint.

Cost estimate summary table

Table 12 summarises cost estimation for Distribution (Low Voltage Growth and Risk) Augmentation.

Table 12: Distribution (Low Voltage Growth and Risk) Augmentation cost estimation

Micro-program	Unit of measure	Description of unit	Approach to costing the micro-program	Cost elements
Un-modelled	Micro-program	N/A	Historic average expenditure, reduced to account for potential overlaps	Average historic percentage applied to annual costs
Modelled	Individual assets	Product Estimates exclusive of transport and accommodation	Product Estimates applied to each work type and applied to forecast volumes. Uplift factor of 9.81% applied to account for transport and accommodation costs and contractual uplift of 1.1%	Labour Materials and Equipment

Un-modelled

Un-modelled augmentation predominantly addresses constraints and issues seen in Ergon Energy's low voltage network. It addresses network constraints that individually are not possible to anticipate, forecast or plan, and is reactive work usually initiated by a network issue or customer complaint.

Approach to costing

Unit costs derived for the un-modelled works are based on a historic average cost.

Approach to costing the micro-program

The basis for the un-modelled augmentation cost is the historical expenditure, produced through analysis of data extracted from Ellipse for each region over a specified time:

- Northern 2008-09 to 2012-13
- Central 2008-09 to 2012-13
- Southern 2008-09 to 2012-13

The data includes expenditure against the following work types:

- Capacity
- Clearance
- Damage
- Inverter Energy Systems
- Isolator
- Other
- Overloaded Distribution Transformers
- Protection
- Power Quality
- Recover Assets
- Reliability
- Voltage

The program estimates are inclusive of mobilisation costs, being transport and accommodation, but excludes overheads.

This historic expenditure has been reduced to account for potential overlaps with the Inverter Energy Systems program by the actual costs recorded against those work types.

Modelled

Units of measure

Establishing the forecast volumes requires lengthy load flow analysis across the whole network to identify all works required to address distribution network constraints.

Ergon Energy modelled the HV distribution network in SINCAL (Siemens Network Calculation) (automated load flow), applying expected future growth, and uptake trends. This automated load flow produced a set of anticipated constraints, based on exceeding asset current ratings or network voltage requirements. For further details on the load flow modelling, see 'Forecast Expenditure Summary Customer Initiated Augmentation' and the 'Network Planning Process' document.

The output of this process is recorded in the Distribution Network Augmentation Plan (DNAP) list, which provides details of the program. However, it must be understood that the DNAP list comprises the current and future identified design constraints assessed against a demand forecast, as the timing of the constraint becomes closer it is validated by on-site inspections, testing and surveying of conditions. If confirmed, the constraint is progressed to a specified project or investment to secure resource planning, procurement or financial approval.

Approach to costing

The product estimates for the distribution augmentation programs (see Table 13) are contingent on the historical average costs, but exclude mobilisation and contractor uplift. Each work type uses a selected efficiently delivered project (no variation) with similar scope to the forecasted type of works with actual direct costs for this project extracted from Ellipse. In the case of those projects that have no comparable scope, an alternate base project with costs adjusted by Ergon Energy's SMEs, is used.

Verification of the product estimates is against prior standard estimates recorded in Ellipse for the period 2006-12. Correcting the estimates by adding/removing labour components ensures that the estimates closely reflect the expected scope and efficient estimate for each type of works.

Approach to costing the micro-program

Building the micro-program estimate involves applying the product estimates to the forecast volumes for each type of work with an uplift factor for mobilisation 9.81% and contractual uplift of 1.1%. The mobilisation factor based on historical cost data of completed distribution augmentation works for the period 2008-09 to 2012-13 and calculating the percentage that transport, travel and accommodation costs made of the total direct costs (exclusive of transport, travel and accommodation costs)

The SINCAL model simulated a forward loaded works micro-program, and therefore, forward loaded expenditure. Ergon Energy has smoothed the delivery of these works over the regulatory control period to ensure deliverability of the micro-program and to assist in resourcing.

Distribution and Low Voltage Augmentation program estimates

See Table 13 for the program estimates (in direct cost) for the above program(s).

Table 13: Distribution Augmentation Program Estimates

	Ellipse estimate code	Investment description	Direct unit cost ($ real 2012-13)
1	MIP1000	Install new Pole Top ABS	15,149
2	MIP1001	Install new Open Delta Regulator in existing network	122,965
3	MIP1002	Install new Closed Delta Regulator in existing network	252,729
4	MIP1003	Create new 11kV/22kV Heavy Conductor Urban OH Feeder	98,839
5	MIP1004	Create new 11kV/22kV Heavy Cond Urban OH Feeder w LV sub-circuit	165,062
6	MIP1006	Upgrade Temperature Rating of Urban 11kV/22kV/33kV feeder	98,325
7	MIP1008	Upgrade Temperature Rating of Rural 11kV/22kV/33kV feeder	54,522
8	MIP1013	Create new Embedded Generation Site	960,557

	Ellipse estimate code	Investment description	Direct unit cost ($ real 2012-13)
9	MIP1014	Install new CB within Zone substation	230,376
10	MIP1015	Install new 11/22kV RMU within existing network	29,961
11	MIP1017	Upgrade Feeder Exit to 400Cu	85,264
12	MIP1018	Upgrade Feeder Exit to 400Al	102,690
13	MIP1020	11kV/22kV Rural express feeder 185Al Conductor per km	313,601
14	MIP1021	11kV/22kV Rural express feeder 240Al Conductor per km	449,043
15	MIP1023	Create new Urban Express Feeder 11kV/22kV 400Al	663,150
16	MIP1024	Create new Urban Express Feeder 11kV/22kV 400Cu	679,242
17	MIP1025	Create new SWER Feeder	15,267
18	MIP1026	Install new SWER Isolator (Greenfield)	95,529
19	MIP1027	Install new SWER Isolator (Brownfield)	100,000
20	MIP1028	Install new SWER Regulator	41,086
21	MIP1029	Install new SWER Recloser	54,903
22	MIP1030	SWER to 1Ph TX Conversion/Transformer	14,232
23	MIP1031	SWER to 1Ph Line Conversion/km	23,091
24	MIP1032	SWER to 3Ph Line Conversion/km	23,846
25	MIP1033	Statcomms 300 kVAR	205,613
26	MIP1034	Low Voltage Relays (LVRs)/ Each	5,513
27	MIP1036	Install LT50's	15,569
28	MIP1037	Install RDT sensors for cable monitoring	23,623
29	MIP1038	Install GUSS unit	298,686
30	MIP1039	Install new Reactor 25/50kVAr	16,737
31	MIP1040	Pole Mounted Distribution Substation Upgrade	19,591
32	MIP1041	Pad Mounted Distribution Substation Upgrade	46,972
33	MIP1042	Small Pole Mounted Distribution Substation Upgrade	15,717
34	MIP1044	Create new Urban Express Feeder Existing Conduit 11kV/22kV 185Al	123,324
35	MIP1045	Create new Urban Express Feeder Existing Conduit 11kV/22kV 400Al	136,255
36	MIP1046	RECONDUCT_UFDR (PRODUCT)	101,744
37	MIP1047	RECONDUCT_RFDR (PRODUCT)	68,509

	Ellipse estimate code	Investment description	Direct unit cost ($ real 2012-13)
38	MIP1136	Install 1ph LV Statcomm (<15kVAr)	4,045
39	MIP1137	Install 3ph LV STATCOM (<50kVAr)	14,974
40	MIP1177	Reactive/Un-modelled	35,226

7.2 Customer Initiated Capital Works

Customer Initiated Capital Works (CICW) forecasts include works required to install 'dedicated' assets, both high voltage and low voltage, to connect an applicant's electrical installation to the network.

This program is broken down into the following categories, customer types and activity, and feeder categories:

- Commercial and Industrial
  - Rural Customer New
  - Urban Customer New
- Domestic and Rural
  - Rural Customer New
  - Urban Customer New
- Subdivision
  - Subdivision Overhead – New
  - Subdivision Underground – New
- Street Lighting
  - Public Lighting – New
  - Public Lighting – Upgrade/Replace
- Services
- Metering

The categories listed above provide the structure of these program levels. A further break down of these categories reflects the difference in the delivery costs between the type of customer (urban or rural).

It is important to note that while the above categories include both ACS and SCS classified works, they have been apportioned appropriately for Ergon Energy's regulatory submission. For further details, refer to the 'Forecast Expenditure Summary Customer Initiated Capital Works' document.

Note there is no unit cost for large customer connects as this is an annualised average. For further details, refer to the 'Forecast Expenditure Summary Customer Initiated Capital Work 2015 to 2020'

Cost estimate summary table (see Table 14) summarises cost estimation for Customer Initiated Capital Works.

Table 14: Customer Initiated Capital Works cost estimation

Sub-program	Unit of measure	Description of unit	Approach to costing the sub-program	Cost elements
Commercial & Industrial Domestic & Rural Street Lighting	Work requests	Top-down estimate of costs based on historical expenditures and quantities These costs include mobilisation and contractor costs	Product estimates applied to each work type and applied to forecast volumes	Labour Materials Equipment Other Contractor
Subdivision	Lot numbers			
Services Metering	Customer numbers	Top-down estimate of costs based on historical expenditures and quantities These costs include mobilisation and contractor costs	Product estimates applied to each work type and applied to forecast volumes	Labour Materials Contractor Equipment Other
Large Customer Connections	Annual Expenditure	Top-down estimate of costs	Historical annual cost based on identified projects	

Units of measure

The volumes are based on total numbers of work requests, lot numbers, and customer numbers for the respective categories shown above in Table 14.

Approach to costing

Unit cost or program estimates for all categories, with the exception of services and metering, are based on historical direct costs recorded for units of work completed during financial periods 2010-11, 2011-12, and 2012-13. These costs include mobilisation and contractors use for the finalised tasks where actual data is available.

The data source is the Ellipse Enterprise Resource Planning (ERP) System, using recorded historic costs of CICW works, and to determine an average unit cost, uses a three-year period from 2010-11 to 2012-13. This period provides a representative sample, which includes improvements and efficiencies implemented to current equipment standards and work practices, thereby reflecting an efficient cost of the forecasted activity.

Unit costs or program estimates for services and metering are based on historical direct costs recorded for each customer service during the financial period 2008-09 to 2013-14 as the developed costs from the 2010-11 to 2012-13 period was considered to have a negative bias. To cater for this abnormality a sample size covering the historical period from 2008-09 to 2013-14 was used. It is assumed that the use of a larger sample size represents a unit cost that is comparable to the bottom up cost estimate. These costs include mobilisation and contractors used for the finalised tasks where actual data is available.

It is assumed that the historical costs are indicative of future costs as:

- the nature of the works is not forecasted to change significantly during the 2015-20 regulatory control period
- the standards and specifications are not forecasted to change significantly during the 2015-20 regulatory control period
- the currency of the data reflects the cost of delivery of the works in the current market.

To ensure an efficient unit cost, the following manual checking for validity of the data was applied in establishment of the unit cost:

- removal of all projects marked ‘unsuccessful’
- removal of any project with a cost less than or equal to $0
- verification of the activity code; removal of five line items where the code did not match
- separation of contestable and non-contestable works.

Approach to costing the sub-program

Estimation of the forecast expenditure for CICW program (see Table 15) involves multiplying the econometrically derived volumes of works with the estimated unit cost for each category. For further details, refer to the ‘Forecast Expenditure Summary - Customer Initiated Capital Works 2015 to 2020.’

Customer Initiated Capital Works program estimates

See Table 15 for the program estimates (in direct cost) for the above program(s).

Table 15: Customer Initiated Capital Works Program Estimates

	Ellipse estimate code	Investment description	Direct unit cost ($ real 2012-13)
1	MIP1161	New Meters/Receivers – SCS	15
2	MIP1162	New Meter Services – SCS	339
3	MIP1271	New Meters/Receivers – ACS	158
4	MIP1272	New Meter Services – ACS	54
5	PCAASPLN	Street Lighting: D-Public Lighting – New	54,045
6	PCAASPLU	Street Lighting: D-P Lighting-Upgrade/Replace	10,757
7	PCCCCRCN	Commercial & Industrial: D-Rural Customer New	51,642
8	PCCCCUCN	Commercial & Industrial: D-Urban Customer New	70,968
9	PCCCDRCN	Domestic & Rural: D-Rural Customer New	28,362
10	PCCCDUCN	Domestic & Rural: D-Urban Customer New	21,159
11	PCCSDSON	Subdivision: D-Subdivision Overhead – New	9,708
12	PCCSDSUN	Subdivision: D-Subdivision Underground – New	6,392

7.2 Photovoltaic related augmentation

The has been a strong uptake of customer connected photovoltaics across the Ergon Energy supply area, predominantly as a consequence of government incentives. The adoption of photovoltaic systems by customers is expected to continue into the future as customers continue to look for expanded choice in supply options. The future growth rate of photovoltaic related augmentation is uncertain, but the expectation is that growth, while less than historical, will continue steadily with photovoltaic size likely to decrease based on changes to the government feed in tariff.

A range of photovoltaic attributed network issues have resulted from both the rapid take-up rate by customers and the fundamental change that bidirectional power-flow poses to network operation.

For details of this program, refer to the document 'Distribution Network Impacts of Photovoltaic Connections to 2020'.

The different network types and the regions provide the structure for this sub-program. The different network types each have different thresholds for photovoltaic penetration and different types of solutions available to address network issues as they emerge. The uptake rates are different for each region and the geographic location of the constraints influences delivery of the solution and consequently the driver for expenditure.

Cost estimate summary table

Table 16 summarises cost estimation for photovoltaic related augmentation.

Table 16: Photovoltaic Augmentation cost estimation

Sub-program	Unit of measure	Description of unit	Approach to costing the sub-program	Cost elements
Photovoltaic related Augmentation	Individual projects	Product Estimates	Product estimates applied to each work type and applied to forecast volumes.	Labour Materials

Units of measure

The solutions to the forecasted constraints caused by photovoltaic installations on the network provide the basis for the forecast volumes. These solutions are in the form of individual projects required to address a constraint. The exceptions are cases requiring re-conductoring where volume is in kilometres of line.

Approach to costing

The program estimates used for this sub-program are the same as those derived for the distribution augmentation modelled program (listed above see Table 13). No mobilisation costs applied because the expectation is that Ergon Energy staff at local depots would resource this work.

The one exception is the installation of a Static Synchronous Compensator (STATCOM). This uses the existing Low Voltage Relay (LVR) product estimate, as the labour hours required are the same based on identical installation processes.

Adjustments to the product estimate account for differences in equipment costs based on an invoice from a supplier and a budgetary quote from another supplier.

Approach to costing the sub-program

Developing the bottom-up cost estimate uses the expected number of various solutions multiplied by the associated program or product estimate cost.

Based on the proposed program of works to address photovoltaic triggered works, this compared the average cost per network for cumulative costs forecast to 2020, with data captured for works flagged as triggered owing to photovoltaic for the period of February to May 2014.

This comparison revealed that the estimate was within 4% of actual observed costs.

7.3 Asset renewal and refurbishment

Timely maintenance and renewal of assets on the network is critical to the long-term capability of the network to provide a safe, secure, and reliable electricity supply. The following are five types of renewal and refurbishment investments aimed at achieving the right balance between risk, operational and capital expenditures:

- Line Maintenance
- Metering
- Public Lighting
- Network Replacement
- Operational Technology
- Telecommunications.

Line Maintenance

This program is broken down into the following defect remediation sub-programs:

- Line defect remediation
- Distribution earthing remediation
- Connector splice replacement
- ‘Figure 8’ colour coded service replacement
- Overhead customer service cable inspection and replacement
- Neutral screened service cable inspection and replacement
- Cast iron pot head replacement
- Laminated cross-arm replacement
- Non-ceramic customer end service fuse replacement
- EDO fuse replacement in high risk areas
- Post natural disaster defect remediation
- RMU mechanism replacement

This section also includes an additional program for Major Items Failed in Service (MIFIS), which is forecast differently to the defect remediation sub-program.

The methodology for estimating expenditure to support Line Maintenance and MIFIS is described in further detail in the ‘Line Asset Defect Management Methodology’.

Unit cost estimation table

Table 17 summarises cost estimation for Line Maintenance.

Table 17: Line Maintenance cost estimation

Sub-program	Unit of measure	Description of unit	Approach to costing the sub-program	Cost elements
Line Maintenance	Individual asset defects	Bottom-up estimate of costs for each task type	Estimates applied to quantities for each task type Mobilisation uplift factor of 52.6% applied where transport, equipment and accommodation costs are not already included in the estimate A contract uplift of 1.1% is applied	Labour Materials Equipment
MIFIS *(*Major Items Failed In Service*)*	Individual asset defects	Top-down estimate of costs based on historical expenditures and job quantities inclusive of transport, equipment and accommodation costs	Estimates applied to quantities based on history for each asset type	Labour Materials Equipment

Defect remediation

Units of measure

The volumes are based on total numbers of tasks forecasted to be completed.

Approach to costing

Different methods are used for estimating unit costs for defect management, post natural disaster defect remediation and the remaining line maintenance sub-programs.

The defect remediation estimating products are based on the field experience and expected scope of typical defect remediation tasks of each type of works. The majority of defect remediation estimating products do not include travel, accommodation, equipment, project support or overhead costs. Distribution Earthing Remediation and Connector Splice Replacement unit costs include travel, accommodation, and equipment.

The Post Natural Disaster Defect Remediation estimating product comprises a historical MIFIS component and estimated costs of remediation of defects following post-cyclone asset inspections.

Approach to costing the sub-programs

Deriving the sub-program costs uses the forecast number of tasks by type at the estimated unit cost estimates (product or program) (see Table 18). An uplift factor for mobilisation costs of 52.6% is used where unit cost estimates do not already include mobilisation costs. This factor is based on the sum of travel, equipment, and supervision costs divided by a standard estimate equivalent cost.

Standard Estimate equivalent cost = (total labour + material cost + other cost) – (labour cost of travel + accommodation cost + cost of depot time + total equipment cost + supervision cost)

Each estimate was linked to the feeder category classification (e.g. urban, long rural, short rural or isolated) and to a financial year. Weighted average mobilisation factors were calculated for each feeder category, based on the quantities of defects within each defect pack. Based on fractions of poles in each feeder category another weighted average was calculated to obtain a single mobilisation factor of 52.56%. The ‘Line Asset Defect Management Methodology’ explains this further.

A contract uplift of 1.1% is applied.

Validation of the line defect remediation sub-program estimate is achieved by back casting the unit costs and uplift factor to defect data for 2010-11 to 2012-13, with an accuracy of -13%. That is, the back-cast costs were lower than historical costs, which reflect an expectation of reductions in average unit rate costs when compared to the previous three years.

Mobilisation uplift factor is not applied to sub-programs such as Distribution Earth Remediation, Connector Splice Replacement, Major Items Failed in Service and Post Natural Disaster Defect Remediation. Unit costs of these sub-programs include travel, accommodation and equipment costs.

Major Items Failed In Service (MIFIS)

Units of measure

The volumes are based on total numbers of failures forecasted for each asset type.

Approach to costing

The estimates are based on historical costs and work order quantities, extracted from Ellipse over the period of 2009-10 to 2012-13, inclusive of travel, accommodation, and equipment costs.

Approach to costing the sub-program

The sub-program costs have been derived by applying the cost estimates (see Table 18) to the forecasted number of failures for each asset type.

Line Maintenance program estimates

See Table 18 for the program estimates (in direct cost) for the above program(s).

Table 18: Line Maintenance Program Estimates

	Ellipse estimate code	Investment description	Direct unit cost ($ real 2012-13)
1	MIP1055	Service Cable – Elevated Work Platform Inspection of 1 Service	105
2	MIP1056	Service Cable – Inspect 2 Services from Ground-line	32
3	MIP1060	Conductor Clearance – Rectify	2,163
4	MIP1061	Cross-arm – Complex – Replace	2,715
5	MIP1064	Cross-arm Kingbolt – Replace	1,057
6	MIP1065	Distribution Transformer – Replace	6,735
7	MIP1068	Operator Platform – Remove	530
8	MIP1069	Service Cable – Replace	1,408
9	MIP1070	Site Access – Repair	933
10	MIP1071	Stay – Install/Replace	659

	Ellipse estimate code	Investment description	Direct unit cost ($ real 2012-13)
11	MIP1072	Steel Pole – Replace	4,208
12	MIP1074	Wood Pole – Nail	1,323
13	MIP1075	Wood Pole – Repair	540
14	MIP1078	RMU Mechanism (4 Switch) – Replace	4,367
15	MIP1079	RMU Mechanism (3 Switch) – Replace	3,917
16	MIP1082	Cast Iron Cable Pot Head – Replace	12,256
17	MIP1084	Replacement of Connector (cost per connector)	309
18	MIP1087	EDO fuse – Replace with Current Limiting fuse	621
19	MIP1089	Non-Ceramic Service fuse on Facia – Replace service and fuse	510
20	MIP1146	Minor Task – Repair	380
21	MIP1147	Cross-arm – Moderate – Replace	2,406
22	MIP1148	Wood Pole – Replace	4,630
23	MIP1149	Cross-arm – Minor – Replace	756
24	MIP1150	Major Items Failed in Service – Switchgear	7,666
25	MIP1151	Major Items Failed in Service – Transformer	8,611
26	MIP1152	Major Items Failed in Service – Underground	11,024
27	MIP1165	Post Natural Disaster Defect Remediation	8,600,194
28	MIP1193	Non SWER Earthing Defect Remediation	2,320
29	MIP1194	SWER Earth Deft Remediation	3,052

Metering

This program is broken down into the following sub-programs:

- Replace metering end-of-life
- Replace metering in-situ
- Replace metering obsolete

The sub-program costs are derived in different ways for the following sub-programs:

- Replace metering end-of-life and in-situ
- Replace metering obsolete

Unit cost estimation table

Table 19 summarises Metering cost estimation

Table 19: Metering cost estimation

Sub-program	Unit of measure	Description of unit	Approach to costing the sub-program	Cost elements
Replace metering end-of-life	Meter	Bottom-up estimates for each component: • Meter – historic average • Installation – standard labour rates	Estimates applied to each asset Uplift factor of 40.42% applied to account for mobilisation and contract uplift of 1.1%	Labour Materials
Replace metering in-situ	Meter	Bottom-up estimates for each component: Meter – historic average Installation – standard labour rates	Estimates applied to each asset Uplift factor of 40.42% applied to account for mobilisation and contract uplift of 1.1%	Labour Materials
Replace metering obsolete	Meter	Top down estimate of costs for average removal based on historic average costs	Estimates applied to each asset exclusive of transport and accommodation costs, which are included in the meter replacement cost.	Labour Materials

Replace metering end-of-life and in-situ

These sub-programs replace populations of meter beyond twice their economic life and showing signs of failure (End of Life program) or families of meters with high rates of non-compliance as discovered via in-situ testing (in-situ program).

Units of measure

Measurement of the volume of meters forecast for replacement uses the number of meters identified as requiring replacement.

Approach to costing

The bottom-up cost estimates (see Table 21) are measured in the number of meters.

The replacement meter costs are based on a current standard of meter suitable for existing configuration. The bottom-up estimates consists of the following components:

- meter cost
- installation cost.

The meter costs are based on a weighted average cost of the meters, including all components, purchased in the 2012-13 period under the current purchasing contract, extracted from Ellipse.

The installation cost is based on the anticipated one-hour installation time and standard labour rates. The unit costs have been compared to the unit costs derived from the metering replacement program currently being undertaken in southwest Queensland and are within 5% accuracy.

The validation used the top down figures from the CICW meter installation program and these were compared to the bottom-up forecast used. These figures were found to be similar.

Approach to costing the sub-program

The bottom-up sub-program cost estimate is based on the expected number of replacement meters multiplied by the bottom-up estimate, with an uplift of 40.42% applied to account for mobilisation and a contract uplift of 1.1%. This mobilisation factor is based on the percentage uplift required to the standard estimate to equate to the cost estimates used for the South West BAZ Meter Replacement Project. . The BAZ program is the planned BAZ (non-compliant meter family) meter replacement program for the southwest region scheduled for 2014-15. These figures derive from a trial replacement program in Dalby, and were used for validation against the sub-program cost estimate of the 2015-20 meter replacement programs.

Replace metering obsolete

This sub-program involves replacing obsolete meter related components, identified while already at site, required to replace a meter in the End-of-life or In-situ sub-program.

Units of measure

The volume of obsolete meter related components forecasted for replacement is measured in the number of meters identified as requiring replacement. These components can range from a complete new customers switchboard to minor electrical equipment located inside such as metering links.

This has been estimated using historic surveys of the types of equipment that require removal and the frequency of these removals per meter replacement. The HMT Meter replacement project from 2009 was used to evaluate the number of obsolete replacements expected. Meters that are to be targeted in the proposed regulatory submission have been adjusted (i.e. rounded down) to allow for meters replaced through normal operational requirements (such as reconfiguration, Inverter Energy Systems, tariff reform) to estimate the number of replacements in the 2015-20 regulatory control period.

Approach to costing

There are no bottom-up estimates (see Table 21) derived for this sub-program, as the metering components requiring replacement will be unknown until onsite. As such, the approach was to develop a unit cost from the top down based on the number of forecasted replacement meters.

The replacement of obsolete meter related components costs are based on removal of obsolete components, as required, while resources are on site installing replacement meters. The resulting product/program cost estimates labour element has been estimated using the data from the historic surveys, giving a weighted average of the time taken to remove obsolete equipment per meter replacement.

The product cost estimate does not include mobilisation costs, as these are included in the cost of the meter replacement program.

Approach to costing the sub-program

The top-down cost estimate is based on the expected number of replacement meters multiplied by the program estimate/unit cost.

Public Lighting

This program is for bulk lamp capital replacement

Unit cost estimation table

Table 20 summarises public lighting estimation

Table 20: Public lighting estimation

Sub-program	Unit of measure	Description of unit	Approach to costing the sub-program	Cost elements
Bulk lamp capital replacement	Individual Asset	Bottom-up program estimate based for each asset	Estimates applied to each asset. A contract uplift of 1.1% applies	Labour Materials Equipment

Units of measure

The volume of luminaires forecast to be replaced is measured in the number of luminaires identified as requiring replacement.

Approach to costing

The bottom-up cost estimate (see Table 21) per unit is measured in the number of luminaires and consists of the following components:

- luminaire cost
- installation cost including labour and plant hire
- materials cost including the actual luminaire (lantern / light head)

The costs are based on labour, materials and equipment costs under current purchasing contracts, extracted from Ellipse.

Approach to costing the program

The sub-program is based on capital spend required to support the bulk lamp replacement program whereby Ergon Energy aims to replace all lamps every three years. The bulk lamp replacement program is covered under operating expenditure. However, when the asset is found to have deteriorated or is damaged a decision to replace the asset is required. This replacement activity, of the whole luminaire or other capital components, forms the basis of this capital program (see Table 21).

Metering and Public Lighting program Estimates

Table 21 shows the program estimates (in direct cost) for the above program(s).

Table 21: Metering and Public Light Program Estimates

	Ellipse estimate code	Investment description	Direct unit cost ($ real 2012-13)
1	MIP1100 & MIP1118	End-of-life for meters and In-situ testing driven non-compliant meter families and Obsolete Meter Technology – inclusive of support	300
2	MIP1100 & MIP1118	Obsolete Meter Technology – inclusive of support	228
3	MIP1273	Bulk Lamp Capital Replacement Program	797

Network Replacement

This program is broken down into the following sub-programs:

- Sub transmission line refurbishment
- Substation power transformer replacement
- Distribution feeder re-conductoring
- Instrument transformer replacement
- Substation HV circuit breaker and switchboard replacement
- Substation isolators replacement
- Substation DC system upgrade
- Substation Static VAR Compensator replacement
- Substation Capacitor Bank replacement
- Protection relay replacement

With the exception of the Protection Relay Replacement Program, the costing has been derived consistently for the above sub-programs. The approach to this program is discussed below. .

Unit cost estimation table

Table 22 summarises the network replacement cost estimation.

Table 22: Network Replacement cost estimation

Program	Unit of measure	Description of unit	Approach to costing the program	Cost elements
Network Replacement	Individual assets	Bottom-up program estimate based for each asset exclusive of transport, accommodation, overheads, and equipment	Estimates applied to each asset Uplift factors of 11.1% for mobilisation and a contract uplift of 1.1%	Labour Materials

Asset replacement programs (except Protection relays)

Units of measure

The forecast costs are based on the numbers of individual assets identified for replacement and refurbishment.

Approach to costing

The unit costs are based on individual assets. Program estimates (see Table 24) for each asset type requiring replacement have been based on a bottom-up build of standard estimates.

That is, the standard estimates were compared to the following and the costs were amended to reflect these more accurate prices.

- Concept (Gate 2) Estimates for an average asset replacement at an average site (compared only for the circuit breaker estimate)
- expert knowledge of Ergon Energy's SMEs
- Reported Regulatory Information Notice (RIN) costs as at 30 June 2012.

The estimates do not include transport, accommodation, and overhead costs.

Approach to costing the program

The program cost has been derived by multiplying the program estimates (see Table 24) by the expected volume of replacement/refurbishment assets of each type, with an uplift of 11.1% applied to account for mobilisation and a contract uplift of 1.1%.

Protection relay replacement

Units of measure

Table 23 shows the units of measurement used to forecast volumes.

Table 23: Protection relay replacement units of measure

Sub-program	Unit
Protection relay replacement	Individual relay
	Half substation
	Full substation
	LV switchboard

The bottom-up unit costs have been developed based on the units outlined in Table 23. These sub-programs may be further broken down into the regions where the required works are identified.

Approach to costing each unit

The bottom-up estimates are based on the expected scope to replace and/or install each type of asset, exclusive of transport, accommodation, and overheads. The costs used to develop the program estimates are based on standard labour rates in Ellipse, and SME knowledge of the cost of materials and equipment.

Approach to costing the sub-program

The bottom-up cost estimate is based on the expected number of replacements of each type multiplied by the associated estimate cost, with a mobilisation uplift factor of 11.1% and a contract uplift of 1.1%.

Network Replacement program estimates

See Table 24 for the program estimates (in direct cost) for the above program(s).

Table 24: Network Replacement Program Estimates

	Ellipse estimate code	Investment description	Direct unit cost ($ real 2012-13)
1.	MIP1005	Create new 11kV/22kV/33kV Medium Rating Rural feeder	66,377
2.	MIP1145	Install Neutral CT (22KV or 11Kv)	49,302
3.	MIP1153	Install set of 3 outdoor HV powder fuses in sub for transformer protection	65,094

	Ellipse estimate code	Investment description	Direct unit cost ($ real 2012-13)
4.	MIP1154	Install set of 3 expulsion fuses (11/22kV) – line or distribution transformer	1,939
5.	MIP1155	Install set of 2 expulsion fuses (33kV) – single phase line or SWER	1,719
6.	MIP1178	Replace 22kV Capacitor Bank-includes transport	843,890
7.	MIP1179	Replace Switchboard Panel 11/22kV	1,215,981
8.	MIP1180	Replace Circuit Breaker 33/66kV or Replace Circuit Breaker 66kV	162,362
9.	MIP1181	Replace Current Transformer 66-132kV	185,912
10.	MIP1182	Upgrade DC Supply 110/125V or Upgrade DC Supply 32/48V	178,963
11.	MIP1183	Replace Outdoor Isolators 66 to 220kV	143,542
12.	MIP1184	Replace 33kV or 66kV Pole Top	2,286
13.	MIP1186	Replace TXF Medium >6.3MVA <32MVA (66/11kV – 20MVA)	1,694,679
14.	MIP1187	Replace Small TX	805,143
15.	MIP1188	Replace Voltage Transformer 66-132kV	201,437
16.	MIP1191	Re-build/Re-conductor frequented (urban) general average	127,373
17.	MIP1192	Re-build /Re-conductor frq(rural) 22/11 HV Line or Rebld 415/240V LV Line	85,097
18.	MIP1222	Retrofit Switchboard	461,687
19.	MIP1224	Transformer Workshop (Dry out)	229,428
20.	MIP1225	Replace SVC	8,761,270
21.	MIP1214	Full Substation Protection Replacement	654,695
22.	MIP1215	Half Substation Protection Replacement	382,888
23.	MIP1216	Replace 1 Protection Scheme Replace	79,460
24.	MIP1217	HV 11kv 22kv Switchboard Protection Replace	414,742
25.	MIP1270	Substation 66kV OD Feeder Bay	771,726

Operational Technology

This work stream consists of the following programs:

- Audio Frequency Load Control (AFLC) equipment asset replacement
- Remote Terminal Unit (RTU) replacement

Unit cost estimation table

Table 25 summarises operational technology cost estimation.

Table 25: Operational technology cost estimation

Sub-program	Unit of measure	Description of unit	Approach to costing the sub-program	Cost elements
AFLC equipment asset replacement	Individual asset	Bottom-up estimate based on expert knowledge of SMEs	Estimates applied exclusive of transport or accommodation costs or overheads Uplift factor of 9.98% applied to account for transport and accommodation costs and contractors uplift of 1.1%	Labour Materials
RTU replacement	Individual asset	Bottom-up estimate based on expert knowledge of SMEs	Standard Estimates applied exclusive of transport or accommodation costs or overheads Uplift factor of 9.98 applied to account for transport and accommodation costs and a contractors uplift of 1.1%	Labour Materials

Audio Frequency Load Control (AFLC) replacement

Units of measure

The forecast volumes are measured in the number of individual components or whole assets are identified as requiring replacement.

Approach to costing each unit

The bottom-up estimates are based on the expected scope to replace and/or install each type of asset, exclusive of transport, accommodation, and overheads. The costs used to develop the program estimates are based on standard labour rates in Ellipse and SME knowledge of the cost of materials and equipment.

Approach to costing the sub-program

The bottom-up cost estimate is based on the expected number of installations of each type multiplied by the associated estimate cost, with a mobilisation uplift factor of 9.98% and a contract uplift of 1.1%.

Remote Terminal Unit (RTU) replacement

Units of measure

The forecast volumes are measured in the number of individual assets that are identified as requiring replacement.

Approach to costing each unit

The bottom-up estimates are based on the expected scope to replace/install each type of asset, exclusive of transport, accommodation, and overheads. The costs used to develop the program estimates are based on standard labour rates in Ellipse and SME knowledge of the cost of materials and equipment.

Approach to costing the sub-program

The bottom-up cost estimate is based on the expected number of installations of each type multiplied by the associated estimate cost, with a mobilisation uplift factor of 9.98% and a contract uplift of 1.1%.

Operational Technology program estimates

See Table 26 for the program estimates (in direct cost) for the above program(s).

Table 26: Operational Technology Program Estimates

	Ellipse estimate code	Investment description	Direct unit cost ($ real 2012-13)
1	MIP1202	Replace AFLC - SFU & Outdoor Unit transmitter and coupling cell. Includes new AFLC study - Medium - 33kv / 220	623,285
2	MIP1207	Replace AFLC - SFU & Outdoor Unit transmitter and coupling cell. Includes new AFLC study - Large - 66kv / 220	1,005,152
3	MIP1211	Replace AFLC - SFU transmitter. Includes new AFLC study	282,492
4	MIP1218	Replace RTUs in a small sub	152,114
5	MIP1219	Replace RTUs in a medium sub	220,057
6	MIP1220	Replace RTUs in a large sub	299,708

Telecommunications

This program is broken down into the following sub-programs:

- CoreNet, Active Network Replacement
- CoreNet, Site Infrastructure Replacement

Unit cost estimation table

Table 27 summarises cost estimation for Telecommunications.

Table 27: Telecommunications cost estimation

Sub-program	Unit of measure	Description of unit	Approach to costing the sub-program	Cost elements
CoreNet, Active Network Replacement	Individual assets	Unit cost developed for each asset type for the following components: • Equipment • Labour	Program Estimate derived by applying unit costs to asset volumes An uplift factor of 4.99% applied to account for the mobilisation costs	Labour Materials
CoreNet, Site Infrastructure Replacement	Individual assets	Unit cost developed for each asset type inclusive of travel.	Program Estimate derived by applying unit costs to asset volumes An uplift factor of 4.99% applied to account for the mobilisation costs	Labour Materials

CoreNet active network replacement

Units of measure

The volumes are based on numbers of individual assets forecast for replacement.

Approach to costing each unit

The unit costs are also based on replacement cost of the individual asset.

The equipment costs for assets are based on the various current supply contracts, unit rates determined from commercially obtained costs and Ergon Energy SMEs. They are exclusive of travel, accommodation, and overheads.

The labour costs for each type of asset are based on standard labour rates, various current labour supply contracts, and labour hours estimated by Ergon Energy's SMEs, exclusive of travel and accommodation.

Calculating the program estimate uses these unit rates.

Approach to costing the sub-program

The costs for this sub-program were estimated based on the scope of the sub-program over the regulatory control period.

The CoreNet Active Network Replacement costs consist of the following components:

- material – based on supply contracts and previously commercially tendered work
- labour – based on previous commercailly tendered experience and from advice from Ergon Energy's SMEs.

A mobilisation factor of 4.99% is applied based on historical cost data of completed telecommunications works for the period 2008-09 to 2012-13 and calculating the percentage that transport, travel and accommodation costs made of the total direct costs (exclusive of transport, travel and accommodation costs). A contractor uplift of 1.1% is applied.

CoreNet Site Infrastructure Replacement

Units of Measure

The volumes are based on the number of individual assets forecast for replacement.

Approach to costing each unit

The unit costs are also based on the estimated replacement costs of the individual asset.

The equipment costs are based on the assets listed in Table 28

Table 28: CoreNet site infrastructure unit cost sources

Asset	Source
Air conditioning	Recent similar project with adjustments to account for difference of scope
Air conditioning Split	Recent similar project with adjustments to account for difference of scope
DC Rack Power System	Supplier provided
Generator	Knowledge of Ergon Energy's SMEs and recent similar projects with adjustments to account for difference of scope
Static Transfer Switch	Supplier provided
Uninterruptable Power Supply	Supplier provided

Approach to costing the sub-program

The costs for this sub-program were estimated based on the scope of the sub-program over the regulatory control period.

The CoreNet Infrastructure Network Replacement costs where based upon individual asset condition based replacements, which are derived by applying unit costs to the forecast volume of replacements. An uplift factor of 4.99% applied to account for mobilisation costs with a contractor's uplift of 1.1%.

Telecommunications program estimates

See Table 29 for the program estimates (in direct cost) for the above program(s).

Table 29: Telecommunications

	Ellipse estimate code	Investment description	Direct unit cost ($ real 2012-13)
1	MIP1166	CoreNet, Site Infrastructure Replacement	67,757
2	MIP1167	CoreNet, Active Network Replacement	149,733

7.4 Network Reliability and Power Quality

This expenditure category has the following programs:

- Reliability of Supply
- Power Quality.

Reliability of Supply

This program consists of the expenditure targeted to address worst performing feeders as they are identified during the next regulatory control period.

Unit cost estimation table

Table 30 summarises reliability of supply cost estimation.

Table 30: Reliability of supply cost estimation

Program	Unit of measure	Description of unit	Approach to costing the program	Cost elements
Reliability	Individual feeders	Top down estimates are created in Ellipse based on historic averages Excludes transport or accommodation costs or overheads	Bottom-up cost estimate based on the expected number of feeders multiplied by the associated estimate cost An uplift factor of 10.63% applied to account for the transport or accommodation costs and contractors uplift of 1.1%	Labour Materials Other

Units of measure

The projects that develop from continuing to monitor and measure Ergon Energy's worst performing feeder will be determined annually and will be based on the feeders that demonstrate consistently poor performance. The estimated unit costs used to forecast the per feeder cost measures have been derived from historical feeder improvement projects. The forecast volumes are based on feeders that consistently demonstrate poor performance.

This program may further be broken down into the feeder types approximated by region based on the percentage of feeders in each region.

Approach to costing each unit

The historic average program costs associated with this program are the historic average costs per feeder based on projects previously delivered under the worst performing feeder program. A review of the actual costs of 30 recently delivered distribution feeder, reliability improvement projects were reviewed to develop the average unit costs per feeder.

Approach to costing the program

The cost estimate is based on the forecasted number of feeders multiplied by the associated average estimate cost, with an uplift factor of 10.63% applied to account for mobilisation costs and a contractor's uplift of 1.1%. The mobilisation factor is based on historical cost data of 30 completed reliability projects for the period 2011-12 to 2013-14 and calculating the percentage that transport, travel and accommodation costs made of the total direct costs (exclusive of capitalised interest, transport, travel and accommodation costs).

Reliability of Supply program estimates

See Table 31 for the program estimates (in direct cost) for the above program(s).

Table 31: Reliability Improvement

	Ellipse estimate code	Investment description	Direct unit cost ($ real 2012-13)
1	MIP1262A	Worst Performing Feeders	113,876

Power Quality

This program is broken down into the following sub-programs:

- Install Power Quality Monitor Units (Next G)
- Install Power Quality Monitor Units (Satellite)
- Install Power Quality Analysers.

The program costs are derived in different ways for the following sub-programs:

- Power Quality Monitors (Next G and Satellite)
- Power Quality Analysers.

Unit cost estimation table

Table 32 summarises Power Quality cost estimation.

Table 32: Power Quality cost estimation

Sub-program	Unit of measure	Description of unit	Approach to costing the sub-program	Cost elements
Install Power Quality Monitors Units (Next G)	Monitor	Historical average costs derived per monitor. Mobilisation costs are included.	Estimates applied to each work type and applied to forecast volumes No additional mobilisation costs added	Labour Materials
Install Power Quality Monitors Units (Satellite)	Monitor	Historical average costs derived per monitor.	Estimates applied to specific project exclusive of transport or accommodation costs or overheads Uplift factor of 12.66% applied to account for mobilisation costs	Labour Materials
Install Power Quality Analysers	Individual project to install 100 analysers to meet an identified constraint	Specific scope for whole project	Estimates applied to specific project exclusive of transport or accommodation costs or overheads Uplift factor of 12.66% applied to account for mobilisation costs	Labour Materials

Power Quality Monitors (Next G and Satellite)

Units of Measure

The forecast volumes for the installation of power quality monitors are measured in individual monitor units.

Approach to costing each unit

The estimate to install the basic power quality monitor with Next G communications is based on the costs incurred when monitors similar to the proposed monitors were installed between 2007 and

2012 (project number CPMNP 11138). These were the project costs recorded in Ellipse for the installation of 1750 units, including travel and accommodation costs.

Building up the estimate that provides the basis for installing the power quality monitor with satellite communications uses the power quality monitor with Next G communications estimate. The change in estimate reflects the additional cost for the satellite equipment in the monitor. To date there have been no satellite monitors installed. However, the Automatic Circuit Recloser strategy is installing equipment of the same nature. The costs for the satellite equipment are based on the costs in the Automatic Circuit Recloser strategy.

Approach to costing the sub-program

The sub-program cost estimate is based on the number of each type of monitor multiplied by the associated estimate. This is inclusive of travel and accommodation costs.

Power quality analysers

Units of Measure

The measurement of the forecast volume for the installation of power quality analysers uses a bulk installation of 100 analysers to provide data for the prioritised feeders that require data analysis.

Approach to costing each unit

There were no individual unit costs derived for the power quality analysers. The cost for all 100 analysers provides the basis for estimate cost for this sub-program.

Approach to costing the sub-program

Costing of the sub-program comprised of an estimate based on the scope to install 100 power quality analysers. Developing the costs used the expert knowledge of Ergon Energy's SMEs. This estimate does not include travel, accommodation, or overheads.

There is an uplift of 12.66% applied to account for mobilisation costs, based on the expected number of sites located at a distance from major centres and requiring crews to stay overnight. This mobilisation factor based on historical cost data of completed power quality projects for the period 2008-09 to 2012-13 and calculating the percentage that transport, travel and accommodation costs made of the total direct costs (exclusive of transport, travel and accommodation costs).

The estimate, inclusive of the mobilisation uplift, when compared to the detailed (Gate 3) estimate and approved project, for the installation of 100 power quality analysers in the 2010-15 regulatory control period, was within ±10% accuracy.

Power Quality program estimates

See Table 33 for the program estimates (in direct cost) for the above program(s).

Table 33: Power Quality

	Ellipse estimate code	Investment description	Direct unit cost ($ real 2012-13)
1	MIP0226	New Power Quality Monitor (field)	1621
2	MIP0268	New Power Quality Monitor (field) – Satellite	3321
3	MIP1268	New Power Quality Analyser (substation) x 1	33,475

7.5 Other Systems and Enabling Technology

This expenditure category has the following programs:

- Network Replacement
- Operational Technology

Network Replacement

This program is broken down into the following sub-programs:

- Substation power transformer bunds
- LV spreader and fuse
- Substation AC system upgrade

Unit cost estimation table

Table 34 summarises Network Replacement cost estimation.

Table 34: Network Replacement cost estimation

Program	Unit of measure	Description of unit	Approach to costing the program	Cost elements
Network Replacement	Individual assets	Estimate based for each asset exclusive of transport, accommodation, overheads and equipment	Estimates applied to each asset. Uplift factors of 11.1% applied to account for mobilisation Also 1.1% uplift for a contractor's uplift	Labour Materials

Substation power transformer bunds, LV spreader and fuse replacement and Substation AC system upgrade programs

Units of measure

The volumes are based on the forecast number of individual assets identified for replacement.

Approach to costing each unit

Accordingly, the unit costs are based the replacement costs of individual assets. The program estimates are based on standard estimates for each asset type requiring replacement.

These estimates were compared to the following and the costs were amended to reflect these more accurate prices:

- The expert knowledge of Ergon Energy's SMEs
- RIN costs as at 30 June 2012.

The standard estimates do not include transport, accommodation, and overhead costs.

Approach to costing the program

Derivation of the program cost estimate multiplied by the forecast volume of replacements assets of each type, with an uplift of 11.1% applied to account for mobilisation costs and a contractor's uplift of 1.1%.

Network Replacement program estimates

See Table 35 for the program estimates (in direct cost) for the above program(s).

Table 35: Network Replacement Program Estimates

	Ellipse estimate code	Investment description	Direct unit cost ($ real 2012-13)
1	MIP1173	Install Bund – Large or Install Bund and Oil Containment	534,668
2	MIP1175	Install Bund – SMALL	271,893
3	MIP1113	Install LV Fuses	7,931
4	MIP1130	Install LV Spreaders (set of 10)	4,202
5	MIP1189	Relocate AC Supply into Switch Yard or Install AC Essential Supply System	219,768

Operational Technology

This program has the following sub-program:

- Protection review
- Sensitive Earth Fault (SEF) protection
- Regulator Remote Communications Strategy

Unit cost estimation table

Table 36 summarises operational technology cost estimation.

Table 36: Operational technology cost estimation

Sub-program	Unit of measure	Description of unit	Approach to costing the sub-program	Cost elements
Protection Review and Sensitive Earth Fault	Individual asset	Bottom-up estimate based on expert knowledge of SMEs	Estimates applied exclusive of transport or accommodation costs or overheads Uplift factor of 11.1% applied to account for transport and accommodation costs and contractors uplift of 1.1%	Labour Materials
Regulator Remote Communications Strategy	Individual asset	Bottom-up estimates based on the identified scope to complete the installation of each type of asset within the sub-program.	Estimates applied exclusive of transport or accommodation costs or overheads Uplift factor of 9.98% applied to account for transport and accommodation costs and contractors uplift of 1.1%	

Protection review

Units of measure

Table 37 summarises the units of measurement used to forecast volumes

Table 37: Protection review units of measure

Sub-program	Unit
Protection review	Individual relay
	Individual recloser with communications
	Individual CT (11kV/22kV)
	Set of two expulsion fuses (33kV)
	Set of three expulsion fuses (11kV/22kV)
	Set of three outdoor HV powder fuses
	Km of distribution conductor

The bottom-up unit costs have been developed based on the units outlined above.

This sub-program may further be broken down into the regions with required works identified.

Approach to costing each unit

The bottom-up cost estimates is based on the identified scope to complete each of the projects within the sub-program. The costs used to develop the estimates are based on standard labour rates and SME knowledge of the cost of materials and equipment. These estimates do not include transport or accommodation costs or overheads.

Approach to costing the sub-program

The bottom-up cost estimate is based on the expected number of installations of each type multiplied by the associated estimate cost, with an uplift factor of 11.1% applied to account for the transport or accommodation costs and a contractor's uplift of 1.1%.

Reviews of Ellipse reports for completed protection projects and recloser projects checked the reasonableness of project costs for similar projects for the last six years, and the scope of work completed for each project for alignment with scope of the estimates.

Sensitive Earth Fault (SEF) protection

Units of measure

Table 38 shows the units of measurement used to forecast volumes.

Table 38: Sensitive Earth Fault (SEF) protection units of measure

Sub-program	Unit
Sensitive Earth Fault (SEF) protection	Individual relay
	LV switchboard

The bottom-up unit costs have been developed based on the units outlined above.

This sub-program may further be broken down into the regions with identified required works.

Approach to costing each unit

The bottom-up cost estimates is based on the identified scope to complete a project within the sub-program. The costs used to develop the estimates are based on standard labour rates and SME knowledge of the cost of materials and equipment. These estimates do not include transport or accommodation costs or overheads.

Approach to costing the sub-program

The bottom-up cost estimate is based on the expected number of installations of each type multiplied by the associated estimate cost, with an uplift factor of 11.1% applied to account for mobilisation costs and a contractor's uplift of 1.1%.

Reviews of the Ellipse reports for completed protection projects and recloser projects check for reasonableness of project costs for similar projects for the last six years, further checking the scope of work completed for each project for alignment with scope of the estimates.

Regulator Remote Communications Strategy

Units of measure

Ergon Energy has approximately 584 high voltage (HV) regulator sites, none of which has remote communications. Ergon Energy's goal by 2030 is for all HV regulators to have remote communications for engineering access and SCADA/DMS data. The measurement of forecast volumes is in number of individual assets, identified as requiring installation, and adhering to certain criteria.

Approach to costing each unit

The bottom-up cost estimates are also based on the costs required for individual assets.

The bottom-up cost estimates are estimates created in Ellipse based on the identified scope to complete the installation of each type of asset within the sub-program. The costs used to develop the estimates are based on standard labour rates and SME knowledge of the cost of materials and equipment. These estimates do not include transport or accommodation costs or overheads.

Approach to costing the sub-program

The bottom-up sub-program cost estimate is based on the expected number of installations multiplied by the bottom-up estimate unit cost, with an uplift factor of 9.98% applied to account for mobilisation costs and contractors uplift of 1.1%.

Operational Technology program estimates

See Table 39 for the program estimates (in direct cost) for the above program(s).

Table 39: Operational Technology

	Ellipse estimate code	Investment description	Direct unit cost ($ real 2012-13)
1	MIP1005	Reconductor HV feeder	66,377
2	MIP1154	Install set of 3 expulsion fuses (11/22kV) – line or distribution transformer	1,939
3	MIP1155	Install set of 2 expulsion fuses (33kV) – single phase line or SWER isolator	1,719
4	MIP1153	Install set of 3 outdoor HV powder fuses in sub for transformer protection	65,094
5	MIP1145	Install Neutral CT (22KV or 11Kv) - D-Other Regulated System Capex	49302
6	MIP1019	Replace Recloser - Protn Review	50,511
7	MIP1215	Half Substation Protection Replacement	382,888
8	MIP1216	Replace 1 Protection Scheme Replace	79,460
9	MIP1217	HV 11kv 22kv Switchboard Protection Replace	414,742
10	MIP1245	Adding Comms to existing regulator - Open Delta	9,459
11	MIP1246	Adding Comms to existing regulator - Closed Delta	10,570
12	MIP1247	Adding Comms to existing regulator - Open Delta	8,348
13	MIP1248	Adding comms and PSU to existing regulator- Open Delta	11,680
14	MIP1249	Adding comms and PSU to existing regulator- Closed Delta	12,791
15	MIP1250	Adding comms and PSU to existing regulator- SWER	10,570
16	MIP1251	Adding comms, PSU and Interface kit to existing regulator - Open Delta	22,585
17	MIP1252	Adding comms, PSU and Interface kit to existing regulator - Open Delta	27,923
18	MIP1253	Adding comms, PSU and Interface kit to existing regulator - Open Delta	17,247

8. Appendices

Definitions, acronyms, and abbreviations

1. Definitions

Term	Definition
A7	Artemis 7 – Portfolio Management Software Package
BAZ Meter Program	Non-compliant meter family replacement program
Compatible Unit	There are three ‘kinds’ of CU: Labour (hours, task), Material (costs), and Contract Services such as crane hire and delivery.
Compatible Unit	Estimating component of which there are three ‘kinds’: Labour (hours, task), Material (costs), and Contract Services such as crane hire and delivery.
Concept estimates	Estimates undertaken by the Concept Design team and which are required at the Gate 2 stage
CoreNet	Ergon Energy’s backbone communications network
Direct cost	Cost for the task, including mobilisation and contract uplift and excluding indirect costs such as overheads. Costs are in 2012/13 real dollars
Ellipse	Mincom Information Management System for financial management and enterprise asset management
Historian	Database software application that logs and stores time-based process data
Meter	Meter (kWh) – A device used to record the amount of power kilowatt-hours used by a customer.
Mobilisation	This relates to travel, equipment transport and accommodation
MVA	1,000,000VA. A volt-ampere (VA) is the unit used for the apparent power in an electrical circuit. Definition of equipment ratings is in MVA because this takes into account both real and imaginary power requirements.
Next G	Third generation mobile telecommunications network operated by Telstra
Product Estimate	An Ellipse estimate that contains Work Orders (WO), Compatible Units, and Ellipse Items
Program Estimate	A grouping of Product Estimates to deliver a Program of Works
Remote Terminal Unit	A remotely controlled unit that gathers accumulated and instantaneous data from telemeter to a specified location
Specified investments	Major projects where there is certainty of the constraint, scope, location and timing.
Standard Estimate	Ellipse estimate based on ‘specific Ergon Energy standard design’, used as a template for the Strategic Estimate. This provides the estimate structure and phases, based on a design and particular assumptions. It contains all the required Products and Compatible Units (CUs) for the labour, materials and contract costs.
Subject Matter Expert	An Ergon Energy Employee with the most knowledge about the content and topic of controlled Ergon Energy documents

Term	Definition
Sub transmission system	Networks supplied at 33 or 66kV, which are inter-connectors or/and line supplying Zone-Substations.
Unit Cost	The cost to undertake a single unit of work
Un-modelled Forecasts	Works that are by nature not conducive to modelling, and based on historical expenditure
Uplift factors	Percentage cost uplifts applied to estimates to account for mobilisation and external contract costs.
Supervisory Control and Data Acquisition (SCADA)	A system of remote control and telemetry used to monitor and control the transmission system.
SINCAL	Siemens Network Calculation

2. Acronyms and abbreviations

The following abbreviations and acronyms appear in this summary document.

Abbreviation or acronym	Definition
AC	Alternating Current
ACS	Alternative Control Service
ADAS	Alternative Data Acquisition Service
AFLC	Audio Frequency Load Control
CICW	Customer Initiated Capital Works
CT	Current Transformer
CU	Compatible Unit
DC	Direct Current
DMS	Distribution Management System
DNAP	Distribution Augmentation Plan
DSA	Distribution System Automation
EDO	Expulsion Drop Out fuse
HHU	Hand Held Units
HV	High Voltage – 132/110/33/11kV
IRC	Investment Review Committee
Km	Kilometre
kV	A Kilo-volt is 1000 Volts
kVAR	1,000 volt amp reactive
LV	Low voltage. Voltage greater than 50V AC RMS or 120V ripple-free DC but not more than 1000V AC RMS or 1500V ripple-free DC
LVR	Low Voltage Relay
MIFIS	Major Items Failed in Service
MVA	1,000,000VA
NIRC	Network Investment Review Committee

Abbreviation or acronym	Definition
OT	Operational Technology
RIN	Regulatory Information Notice
RMU	Ring Main Unit
SCADA	Supervisory Control and Data Acquisition (of the Power System)
SCS	Standard Control Services
SME	Subject Matter Expert

Appendix B. References

1. Compliance Documentation

Name	Description
National Electricity Rules Clause 6.5.7(e)(6)	Statutory instrument made under the *National Electricity (South Australia) Act 1996* governing the National Electricity Market and the regulation of market participants including Ergon Energy. Note: The Australian Energy Regulator must have regard to the relative prices of capital inputs
National Electricity Rules NER Clause S6.1.1.(2)	Statutory instrument made under the *National Electricity (South Australia) Act 1996* governing the National Electricity Market and the regulation of market participants including Ergon Energy. Note: The method used for developing the capital expenditure forecast

2. Supporting Documentation

Name	Description
Forecast Expenditure Summary Customer Initiated Capital Works 2015 to 2020	The purpose of this summary document is to explain and justify Ergon Energy's Customer Initiated Capital Works expenditure for the next regulatory control period, 1 July 2015 to 30 June 2020.
Forecast Expenditure Summary Corporation Initiated Augmentation 2015 to 2020	The purpose of this summary document is to explain and justify Ergon Energy's Corporation Initiated Augmentation capital expenditure for the next regulatory control period, 1 July 2015 to 30 June 2020.
Forecast Expenditure Summary Asset Renewal 2015 to 2020	The purpose of this summary document is to explain and justify Ergon Energy's Asset Renewal capital expenditure for its standard control services for the next regulatory control period, 1 July 2015 to 30 June 2020.
Forecast Expenditure Summary Other System and Enabling Technology 2015 to 2020	The purpose of this summary document is to explain and justify Ergon Energy's Other System and Enabling Technology capital expenditure for the next regulatory control period, 1 July 2015 to 30 June 2020.
Forecast Expenditure Summary Reliability and Quality of Supply 2015 to 2020	The purpose of this summary document is to explain and justify Ergon Energy's Reliability and Quality of Supply capital expenditure for next regulatory control period, 1 July 2015 to 30 June 2020.
Network Investment Review Committee (NIRC) Charter dated July 2014	The purpose of the NIRC is to facilitate the prudent and efficient management of all network related capital and operating expenditure of Ergon Energy in accordance with the Network Optimisation Plan.
Investment Review Committee Charter dated July 2014	The document details the Charter and specifies the terms of reference and strategic and tactical oversight functions of the Investment Review Committee.
Ergon Energy's Financial Delegation of Authority	The purpose of Ergon Energy's Delegation of Financial Authority is to ensure that the appropriate levels of financial controls exist.
Network Portfolio Project and Program Investment Approval Governance Ver 2.0 (Gated Methodology)	This paper describes the 'Capital Works Project and Program Investment Approval Governance Process'.
About Ellipse Estimation Ver 1.8, Jan 2014	The main aim of this Reference is to explain the Ellipse estimating for major projects. This is for users and managers who are involved or interested in the estimating approach.

Name	Description
Distribution Network Impacts of Photovoltaic Connections to 2020	The aim of this document is to describe the work performed to assess the network impacts of inverter energy systems and to determine the required capital and operational expenditure to manage their integration on the Ergon Energy network.
Line Asset Defect Management Methodology	The purpose of this document is to describe Ergon Energy's practices, plans and forecasts for the management of defects on the overhead and underground distribution and sub transmission network.

3. Models

Name	Description
Network Capital Expenditure Forecast Model	The purpose of the Excel based spreadsheet is to provide a transparent view of the methodology taken in the development of its direct cost Standard Control Services (SCS) and Alternative Control Services (ACS) network capital expenditure forecasts for its next regulatory control period, 1 July 2015 to 30 June 2020.