Capital Expenditure Overview - ICT

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Information and Communications Technology

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Approval and Document Control

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Glossary

Term	Description
ACS	Alternative Control Service
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
AMI CROIC	AMI Cost Recovery Order in Council
Capex	Capital Expenditure
CY	Calender Year
DMS	Distribution Management System
DNSP	Distribution Network Service Provider
ECE	Effortless Customer Experience
EDPR	Electricity Distribution Price Review
ERP	Enterprise Resource Planning
FTE	Full Time Equivalent
FY	Financial Year
GIS	Geographic Information System
ICT	Information Communications
IT	Information Technology
LAN	Local Area Network
LV	Low Voltage
MG	Multinet Gas
NECF	National Energy Customer Framework
NEM	National Electricity Market
NER	National Electricity Rules
OMS	Outage Management System
Opex	Operating Expenditure
PMO	Project Management Office
RIN	Regulatory Information Notice
SCADA	Supervisory Control and Data Acquisition
SCS	Standard Control Services
SME	Subject Matter Expert
SMS	Short Messaging Service
UE	United Energy
WAN	Wide Area Network

1. Purpose of this document

The purpose of this document is to assist the AER and our customers in understanding our forecast capital expenditure. It focuses on a specific sub-category of capital expenditure; non-network, Information and Communications Technology (ICT).

The document presents a forecast for our capital expenditure (capex) in the ICT sub-category for delivery of both our standard control services (SCS) and alternative control services (ACS) for the next regulatory control period (1 January 2016 to 31 December 2020).

Our ICT assets are integral to our business operations. ICT systems support almost all of our core business functions (as shown in Table 1). Without on-going investment to maintain and refresh our ICT assets, we will not be able to continue to meet the information needs of our customers, achieve the system availability and performance levels required by customers or to meet future industry and regulatory challenges.

Table 1 Functions supported by our ICT systems

Function	Explanation
Customer and Stakeholder Management	Provision of services and/or information to internal and external stakeholders (including customers, retailers, government agencies, regulator, partners and employees).
Network Management	Management, monitoring and control of the distribution network including responding to faults/emergencies, and analysis and optimisation of the network.
Asset Management	Strategic planning and management of assets, work programs and resources, including network extensions, inspections, maintenance and construction.
IT Management	IT capabilities enabling operations and supporting planning and management of the business, including managing applications, IT portfolio, infrastructure, architecture, security and IT services.
Works Management	Management of work programs and resources for network extensions, inspections, maintenance and construction.
Meter Data and Revenue Management	Management of meter data, connection points and meter services, including the provision of data to market and management of service orders and metering faults.
Information Management	Capabilities required to effectively manage large amounts of structured and unstructured information across the business.
Business Support Management	Corporate capabilities required to support the business including finance, HR, risk & audit, legal, supply chain & logistics and OH&S.

This document aims to provide the reader with a full understanding of our ICT capex forecasts. However, because this is an overview document, it necessarily addresses some matters at a relatively high level and refers to other documents for further detail. These documents are listed in Section 7.

This overview document provides details of actual, estimated and forecast IT capex for the current (1 January 2011 to 31 December 2015) and the forthcoming (1 January 2016 to 31 December 2020) regulatory control periods. All capex is presented in real 2015 dollars and is expressed in total costs (i.e. direct costs plus escalations and overheads).

2. Structure of this document

This document is structured as follows:

- Section 3 details our IT capex profile for the current and forthcoming regulatory control periods;
- Section 4 explains the conceptual nature of our IT capex and why it is necessary;
- Section 5 details the IT specific capex forecasts and timings for each of our programs for the next regulatory control period;
- Section 6 explains how our IT capex forecast meets the capex objectives and criteria in the rules;
- Section 7 details the supporting documentation relevant to our capex forecast;
- Appendix A explains and justifies our actual IT capex against the AER’s allowance in the current regulatory control period as well as the outcomes that it has delivered;
- Appendix B presents our approach to management and governance of the program; and
- Appendix C presents our expenditure forecasting method for forthcoming period.

3. Expenditure profile 2011 to 2020

This section examines our IT capex profile for the current and forthcoming regulatory control periods. This is intended to provide the reader with a clear understanding of the profile of our forecast ICT capex that will be explained and justified in the remainder of this overview document. This capex category includes all areas of IT and communications including corporate applications, asset management, network management and geospatial applications as well as IT infrastructure. This category includes expenditure on central elements of SCADA and network control systems but excludes field and network-based elements of SCADA and network control systems.

Our forecast expenditure for the 2016-2020 regulatory control period is presented below in Table 2.

Table 2 Forecast expenditure for 2016 to 2020 ($2015M)

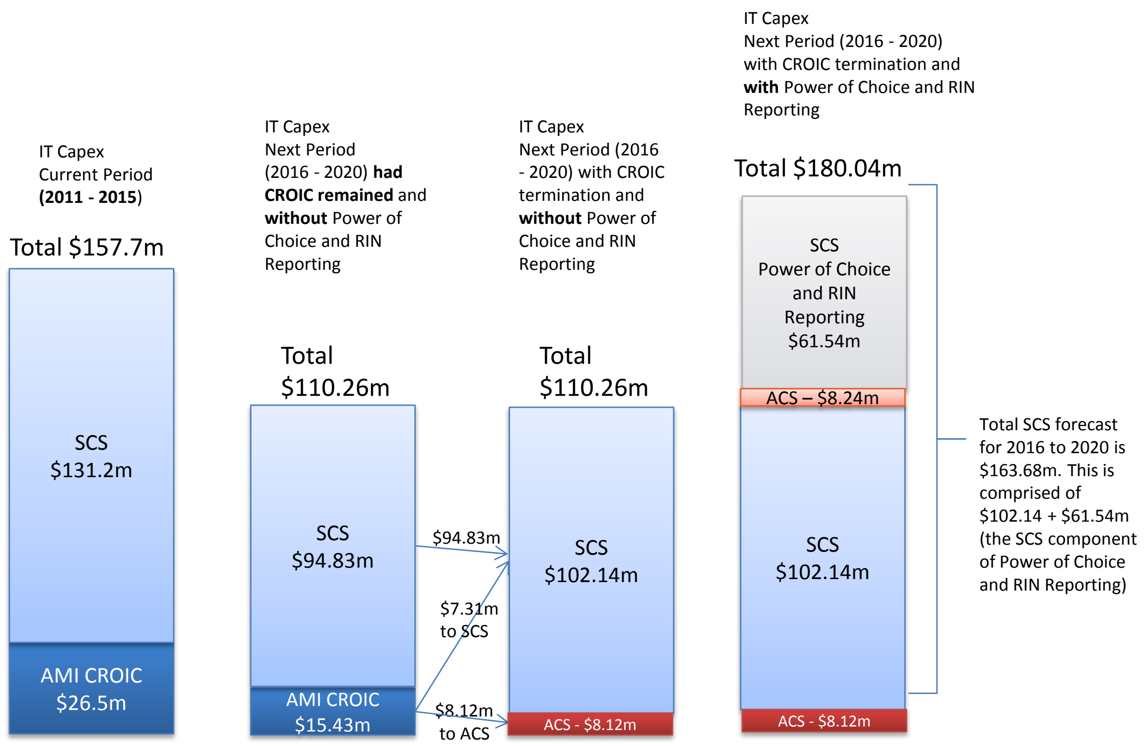
	2016	2017	2018	2019	2020	TOTAL
Regulatory Proposal (SCS)	30.7	44.9	37.0	21.7	29.3	163.7
Regulatory Proposal (ACS - metering)	7.4	4.9	0.4	0.8	2.9	16.4
Total	**38.1**	**49.8**	**37.4**	**22.6**	**32.2**	**180.1**

Three factors need to be considered when comparing this forecast to the IT capex incurred in the current regulatory period:

- **The termination of the Advanced Metering Infrastructure Cost Recovery Order in Council (AMI CROIC) cost recovery process:** The AMI rollout and service level obligations had a significant impact on our IT systems environment. In addition to the costs of new and modified applications, we also incurred costs for new ICT infrastructure, data centre facilities and disaster recovery capabilities. Many of our core systems were impacted by the AMI rollout and service level requirements. The impact extended well beyond those systems specifically required for metering. Some of our IT capex costs are currently recovered under the AMI CROIC. For example the recurrent IT capex associated with the systems implemented for the AMI program are currently recovered through this process. This IT capex will be allocated to SCS in the next regulatory period, due to the termination of the AMI CROIC cost recovery process at the end of 2015. The termination of the AMI CROIC results in an overall increase to our forecast ICT SCS capex of $7.3 million (excluding Power of Choice and RIN Reporting) when compared with the current regulatory control period;
- **The "Power of Choice" reforms:** Substantial reforms to the National Electricity Market (NEM) are underway following recommendations to the state and federal governments by the AEMC's Power of Choice review. Many of the detailed requirements are not defined at this time. However, as it is clear that the changes to the rules will have a significant impact on our ICT expenditure, we have included the costs of meeting the requirements of these reforms in our forecast. The costs associated with Power of Choice reforms result in an increase to our forecast ICT capex of $45.4 million ($37.2 million SCS and $8.2 million ACS - metering); and
- **The AER's new RIN reporting expectations:** The AER has clear expectations that future RIN reports will be largely based on actual data rather than estimates. However the exact nature of that expectation is unclear and different interpretations lead to very different estimates of expenditure. Meeting this expectation will require significant IT capital expenditure in the next regulatory period and we have therefore included an estimate of the costs. The costs associated with meeting RIN reporting expectations result in an increase to our forecast ICT SCS capex of $24.34 million.

A valid comparison of United Energy's SCS Non-Network IT Capex between the current and next regulatory periods must take these three factors into account. A valid comparison of costs between the two periods excludes the costs for Power of Choice and RIN Reporting and takes into account the costs that would have been recovered under the CROIC had it continued. On this like-for-like basis (as shown in Figure 1) it can be seen that our overall IT expenditure in the next regulatory period would have reduced by $45.8 million (from $156.1 million to $110.3million), or approximately 29 per cent, had we not been required to meet the additional requirements of Power of Choice and RIN reporting.

Figure 1: Comparison of ICT capex between the current and future regulatory period



Our ICT capex in the current regulatory period (2011 to 2015) will be slightly (4.3%) over the AER's allowance (see Table 3). In this period, we have successfully delivered a challenging ICT capital program, including several large ICT projects that were critical to our business transformation. We implemented a major ERP replacement project, a system separation project, two data centre relocations, a major infrastructure refresh, updates of the distribution management system and upgrades of market systems.

Table 3 Actual and forecast ICT SCS expenditure for 2011 to 2015 ($2015M)

	2011	2012	2013	2014	2015	TOTAL
Regulatory Proposal	26.70	41.44	31.29	18.19	8.18	125.81
Distribution Determination	26.70	41.44	31.29	18.19	8.18	125.81
Actual / Forecast	56.14	14.48	11.97	24.27	24.35	131.20

The scope of the ICT program and the projects completed were closely aligned to the ICT Capital Plan presented to the AER five years ago (see further detail in Appendix A). Where changes and reprioritisations to the program were necessary, these were managed through a robust ICT governance structure.

4. Nature of expenditure

4.1. Overview

This section provides a brief overview of the conceptual nature of our forecast ICT capex. Expenditure during the forecast period is driven by a number of internal and external factors:

- Changing consumer needs and expectations, with increasing demand for web-based services, smart phones, timely and accurate information, and an increasing awareness of alternative sources of energy, such as solar panels;
- The Australian Energy Market Commission's (AEMC's) Power of Choice reforms which will require upgrades to IT systems to support the electricity market in meeting changing consumer needs;
- The AER's expectations that future RIN reports will be largely based on actual data rather than estimates;
- Chapter 6 of the National Electricity Rules (NER)[1] which requires Distribution Network Service Providers (DNSPs) to deliver a capex program that meets expected demand for SCS, complies with regulatory obligations associated with SCS, maintains the quality, reliability and security of the distribution system through the supply of SCS and addresses the concerns of customers;
- Chapter 5, Part B of the NER, requiring a DNSP to meet or manage capacity constraints in the electricity distribution network as a result of growth in maximum electricity demand; and
- Changes in the patterns of demand for electricity due to increasing prices, the availability of affordable distributed generation (e.g. solar panels), increasing concern over environmental issues, and the adoption of energy efficient systems and appliances.

We have developed an IT Capital Program[2] to drive the definition of our IT capex program for 2016 to 2020. The strategy presented in our IT Capital Program addresses the factors listed above and also takes into account the opportunities presented by new ICT technologies and services such as cloud services, digital communications/social media, sensor technology / smart grid, analytics and mobility.

Our forecast ICT program for 2016 to 2020, based on the strategy presented in our IT Capital Plan, will deliver six key outcomes:

1. **Deliver new capability to meet** changing customer needs and growing expectations. We will implement ICT solutions that address the needs and expectations of customers by providing services and information via web-based and mobile communication channels;
2. **Ensure ongoing performance, resilience and safety in the changing distribution network.** We will implement ICT solutions that support maintaining the ongoing performance and resilience of our distribution network in order to match changing demand and usage profiles;
3. **Ensure readiness to achieve regulatory requirements.** We will invest in ICT systems to ensure that we are ready to meet regulatory change requirements driven by industry reforms such as "Power of Choice" and are able to meet the AER's expectations for actual data in RIN reporting;
4. **Utilise field mobility and other technologies to automate field work processes with service providers** – We will combine increasingly mature and low cost mobility technologies with our enterprise resource planning (ERP) system to reduce manual intervention in processes for managing the work carried out by field work forces. This will increase security of supply of the network and the quality of distribution services;
5. **Improve asset planning and management through analytics and reporting**. We will utilise advanced analytics technology to process and produce reports based on the data captured from

1 Australian Energy Market Operator, *National Electricity Rules*, Version 66

2 IT Capital Program 2016 to 2020. United Energy.

network monitoring applications and field workforces using mobility technology. This data will be used to improve planning and management of assets; and

6. **Maintain systems to industry standard to avoid increased risk of disruption to customers and to retain levels of efficiency.** Having completed a major overhaul of our ICT systems in recent years, we will continue to invest to ensure that these systems are refreshed to maintain the industry standard required to meet the needs of our customers.

The focus of the investment outlined in this document is on achieving the outcomes listed above. This investment in ICT will not produce immediate financial benefits.

Where we have opportunities to invest in ICT to produce immediate financial benefits such as operational cost savings, this investment would be self-funded.

The remainder of this section outlines the nature of the expenditure required to deliver the six outcomes above in further detail.

4.2. Meeting Customer Needs and Expectations

Our focus for the forthcoming regulatory period is to put customers at the centre of our business.

Increases in energy costs, greater use of web-based services and smart phones and increasing awareness of alternative sources of energy, such as solar panels, are all combining to change the way in which customers view energy providers.

Customers want communication with us to be simple and effortless. Mobile technology and digital communications are now pervasive. Customers expect information to be available wherever and whenever required.

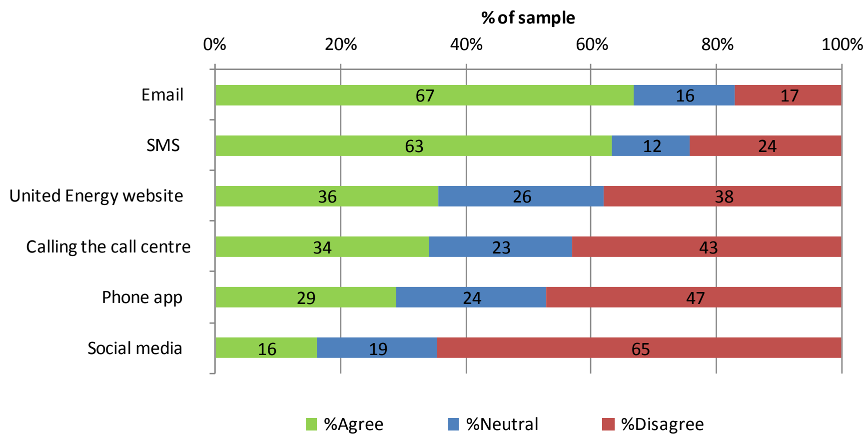
While a reliable supply of electricity is important to customers, information about energy supply is also seen as critical. Research and customer consultation carried out by KPMG on our behalf shows that a key issue for customers is not so much that power goes off, but knowing when it is going to come back on. In other words, customers are looking for rapid and accurate information.

The key findings from the customer research carried out by KPMG indicated that:

- Customers want better communication about planned and unplanned interruptions; and
- Customers generally want better and more timely information and guidance to enable them to control their electricity consumption and bills;

Customers are increasingly preferring digital communications channels over use of telephone call centres. Our research (Figure 2) shows that email and SMS are preferred methods for notifying customer of unplanned interruptions.

Figure 2 Customer notification of unplanned interruptions



Our retailers also want communications with us to be streamlined. Retailers require communications to be efficient and expect that we will be able to track the status of their requests and limit the amount of paperwork.

ICT applications and systems delivered in our 2016 to 2020 IT program will support us in meeting our customers' and retailers' needs and expectations. Together with our Effortless Customer Experience program, our ICT projects will:

- Provide more accurate and timely information on unplanned outages to assist customers' decisions on how to respond at home and at work, reducing the cost and inconvenience to customers of supply interruptions;
- Provide online customer claim facilities and tracking tools, increasing the ease and convenience to customers in making a claim;
- Allow customers to receive notifications and energy consumption data, and to receive maximum benefit from AMI;
- Implement a self-service new-connections portal for customers, electricians and developers to streamline the connections process, thereby saving time and reducing costs for our customers; and
- Meet our retailers' requirements for streamline communications by implementing capabilities to track retailer requests and paperwork in the customer portal.

In many cases, these projects will build upon systems and capabilities implemented during the current and previous regulatory periods including:

- The AMI meter and network management system, implemented as part of our AMI program, that can gather usage and outage information from AMI meters installed throughout our network;
- The CRM capability implemented as part of our 2011 to 2015 IT capex program for customer claims and complaints; and
- The Energy Easy customer portal which was implemented as part of our AMI program that already provides information to customers about their energy usage.

The cost of these projects to meet customer needs and expectations is forecast at $3.85 million (all SCS) over the 2016 to 2020 period. This figure excludes projects that are required to meet Power of Choice regulatory requirements, however the projects will benefit from the systems and capabilities implemented for Power of Choice. The cost estimate of $3.85 million is based on the assumption that the Power of Choice projects will proceed. If those projects did not proceed, the costs of the 'effortless customer experience' IT projects would increase.

The projects presented above deliver direct benefit to customers. However, customers will also benefit indirectly from all of the projects presented in the following sections which together ensure that we continue to operate effectively and efficiently as a business and maintain the performance of the distribution network.

4.3. Ensure ongoing performance, resilience and safety in the changing distribution network.

Our ability to monitor and manage network performance is currently limited and largely reactive, relying predominantly on routine maintenance, fault management and complex analysis of data from the telemetry network.

As the nature of the distribution network changes, with increased use of solar generation and demand response services, there is an increased risk of disruption to customers. Investment in improved network management applications is therefore required to maintain and enhance our capability to proactively manage network performance and resilience and thus maintain the current risk level in the face of increased failures. This investment will allow us to defer network infrastructure investment and to comply with regulatory requirements by actively managing the distribution network in real-time.

Key projects in our 2016 to 2020 program include:

- **Network Analytics** – Implementation of improved analysis of real-time data to proactively identify Neutral Integrity issues, optimise asset utilisation and identify energy theft. This capability assists UE to identify failing assets helping to avoid unplanned outages and improve network quality. One specific benefit of this project is that costly site visits for neutral integrity testing can be avoided while still ensuring the safe provision of electricity to the end customer;
- **DMS - LV Management** - DMS is currently used to monitor and control High Voltage distribution. This project is to extend this capability to the Low Voltage Network. This capability allows us to maintain the quality, reliability and security of the changing distribution network. This project is also a key enabler of improved customer service through the provision of more accurate customer level information on planned and unplanned outages and more effective management of sensitive and life-support customers;
- **OMS - Smart Grid Gateway Extensions**. Provision of basic integration of AMI smart meters to facilitate the "last Gasp" and meter ping functionality. This capability will increase the accuracy of notifications about outages and therefore improve our ability to meet customer expectations for accurate outage information; and
- **DMS - Feeder Load Management**. Provides the capability to analyse real-time data of current feeder loads to remotely reconfigure loaders for load balancing and loss minimisation. This capability allows us to improve the utilisation of network assets during peak demand situations and therefore to defer additional capital expenditure on the network.

These projects will support us to comply with regulatory obligations and to maintain the quality and reliability of the distribution system.

The projects presented above build upon the investment made in the current period including our upgrade of our distribution and outage management systems and our investment in analytics platforms.

The cost of these projects to ensure ongoing performance, resilience and safety in the changing distribution network is forecast at $21.58 million (all SCS) over the 2016 to 2020 period.

4.4. Ensure readiness to achieve regulatory requirements

4.4.1. Power of Choice Reforms

Substantial reforms to the National Electricity Market (NEM) are underway following recommendations to the state and federal governments by the AEMC’s Power of Choice review – giving customers options in the way they use electricity.

The package of reforms is designed to support the electricity market in meeting customers’ needs over the next 15-20 years. It provides more opportunities for customers to make informed choices about the way they use electricity based on the benefits that end use services provide. Ultimately, customers will be in the best position to decide what works for them.

The AEMC’s recommendations include measures to:

- Reform distribution network pricing principles to improve consumer understanding of cost reflective network tariffs and give people more opportunity to be rewarded for changing their consumption patterns;
- Expand competition in metering and related services to all consumers, putting greater discipline on competitive metering suppliers to provide services at efficient cost and consistent with consumer preferences;
- Clarify existing provisions regarding the ability of the market operator, AEMO, to collect information on demand side participation to make its market operational functions more efficient;
- Give customers better access to their electricity consumption data;

- Establish a framework for open access and common communication standards to support contestability in demand side participation end user services enabled by smart meters. This will support consumer choice;
- Introduce a new category of market participant for non-energy services in the National Electricity Rules to facilitate the entry of innovative products for consumers;
- Reform the application of the current demand management and embedded generation connection incentive scheme to provide an appropriate incentive scheme to provide an appropriate incentive for distribution businesses to pursue demand side participation projects which deliver a net cost saving to consumers; and
- Establish a new demand response mechanism in the wholesale market - option for demand side resources to participate in the wholesale market for electricity.

Following the 'Power of Choice' review by the AEMC in 2013, activity is currently underway to introduce a series of changes into the National Electricity Market which will impact our IT systems.

A summary of the forecast changes is presented in the following table (Table 4).

Table 4 Forecast changes as a result of Power of Choice

Regulatory Change	Assumptions and Impacts on our systems
Demand response mechanism – option for demand side resources to participate in the wholesale market	A rule change and new procedures will be introduced to add a new market role of 'Demand Response Aggregator (DRA)'. Details of demand response events will need to be recorded in the data warehouse and sent to the existing DMS system to inform Network Operations. The introduction of the new DRA role will require changes to the customer management and billing system (SAP ISU) and the Meter Data Management (Itron) system. New market transactions will require changes to be made to the market system infrastructure (WebMethods) and will also require changes to SAP (ISU).
Embedded networks	A rule change and new procedures will be introduced to add a new market role of 'Embedded Network Administrator'. Changes to our IT systems are required to: • Establish capabilities to support the Embedded Network Manager role and associated relationships to on-market children and to parent NMI. Provide support for new market processes for management of embedded network • Support market transactions for life support customers. • Provide support for meter and participant churn and associated market transactions. The introduction of embedded network manager role will require changes to our customer management and billing system (SAP ISU). New market transactions will be implemented using WebMethods A2A and B2B infrastructure and will require changes to SAP (ISU) and the Itron meter data management system.
Multiple trading relationships	A rule change and new procedures will be introduced to support new types of services and service providers. This will change the current one-to-one relationship between meter number, settlement point and NMI. Significant changes will be required to our customer management and billing system (SAP ISU), our market system and our WebMethods A2A and B2B infrastructure and our Meter Data Management (Itron) system. These changes are required to: • Establish capabilities to enable multiple retailers to be associated with a connection point. • Establish the settlement point within our systems. • Support parallel, subtractive and net metering. • Provide for disconnection/reconnection by retailer where feasible. • Enable each retailer at the connection point to have one or more meters. • Enable each meter to have a metering coordinator. • Provide support for meter and participant churn and associated market transactions. Meeting the requirements of multiple trading relationships is made more complex (and costly) because of the need to support multiple alternative modes of operation.

Regulatory Change	Assumptions and Impacts on our systems
Introduction of national metering competition	Significant changes will be required to our customer management and billing system (SAP ISU), our market system and our WebMethods A2A and B2B infrastructure and our Meter Data Management (Itron) system. These changes are required to: • Establish the metering coordinator role and enable accreditation for this role. • Provide support for meter and participant churn and associated market transactions. • Enable and manage receipt of metering data and meter and data stream configuration from third parties for all meter types. • Establish communications infrastructure and systems to enable open access to metering data and functions and the adoption of the Shared Market Protocol. This includes capabilities to access other metering coordinators' systems and provide access to our metering coordinator's system. • Support transactions for retailer load control including appropriate network business approval process. • Establish capability for real time metering transactions. • Provide support for metering to the national minimum standard
Improved customer transfer systems	Following the review by AEMO, revised customer transfer procedures will be introduced to on improving both the timing and accuracy of the transfer process. Changes will be required to our customer management and billing system (SAP ISU), our market system and our WebMethods A2A and B2B infrastructure to: • Improve automation of consumer transfer process enabling consumers to switch retailers more efficiently. • Allow transfers on estimates for manually read meters. • Address process and data quality issues (create standard address format and cleanse NMI standing data) • Enable the LNSP to become the master for address data (new market transactions required). • Implemented an improved rejections process. • Support improved reporting and statistics on transfer performance.
Consumer access to metering data	A rule change will be introduced requiring us to provide consumers with access to metering data. To meet this requirement, a new or modified application will be required to: • Establish capabilities to enable consumers (or their authorised agents) to register to receive consumption data and provide explicit and informed consent for sharing of consumption data with others. • Provide support for all meter types and configurations (including non-interval meters). • Provide information in a new national standard format. • Enable access to up to two years of metering data. • Provide summary reports e.g. peak, off peak and shoulder as required by the new procedures The infrastructure and application will be established to deliver expected transaction volumes and ensure consumer's data is secure and not shared with unauthorised parties.
Embedded generation	New procedures will be introduced to support embedded generators. Changes will be required to SAP (ISU) to: • Establish capabilities to support the Embedded Network Manager role and associated relationships to on-market children and to parent NMI. • Provide support for new market processes for management of embedded networks. • Support market transactions for life support customers. • Provide support for meter and participant churn and associated market transactions.

Table 4 shows that our core systems will be significantly impacted by the Power of Choice reforms. Many of these systems were implemented to meet the stringent high performance requirements of AMI. Some of the modifications require fundamental changes to the design principles of these systems and therefore the changes will be costly and time consuming. As these changes are market-wide, it is assumed that significant industry interaction and industry testing will be required. The costs will be impacted by the timing of the implementation and the extent to which changes can be consolidated into a number of separate releases.

Following impact assessments carried out in consultation with our application management service provider, the total cost of these projects to ensure readiness to meet the power of choice regulatory requirements is forecast at $45.44 million ($37.2 million SCS and $8.24 million ACS - metering) over the 2016 to 2020 period.

4.4.2. Regulatory Information Notice (RIN) Reporting

The AER has clear expectations that future RIN reports will be largely based on actual data rather than estimates. Meeting this expectation will require significant IT capital expenditure in the next regulatory period. However the exact nature of that expectation is unclear and different interpretations lead to very different estimates of expenditure.

We have performed a preliminary gap analysis based on our interpretation of the DNSP RIN reporting requirements. This analysis has identified a series of requirements for modifications to existing systems and processes:

To move from 'Non-Inherently Estimated' to 'Actual Information' (where possible), we will need to modify processes, work practices and systems. We will need to perform data cleansing, collect and populate missing information and train our staff in the new systems and processes. Modifications will be required to our SAP-ERP, GIS and DMS systems so that they can store the missing data, and in some cases, perform data cleansing. Interfaces between systems will need to be modified to enable transfer of information as required.

A Business Intelligence (BI) solution is required to support the production of RIN information including history and associated analytics. Further enhancements will be required to the Mobility Solution being deployed (through a separate project) to support the field-based capture of information that is not captured today (including information on cross-arms, services, surge-diverters etc.) so that this information can be stored in the source systems.

Our field network service providers will also be impacted. Our service providers will need to populate missing or incorrect data and then continue to update data. This will require our service providers to change work practices and procedures and to modify their internal information systems. These changes then require services providers to retrain their personnel.

Based on our preliminary gap analysis, the costs associated with meeting RIN reporting expectations result in an increase to our forecast ICT capex of $24.34 million (SCS) in the next regulatory period.

4.5. Utilise field mobility and other technologies to automate field work processes with service providers

The increasing availability of low-cost smart phones, tablets and notebooks for use by employees and subcontractors creates a series of opportunities for energy network operators to improve the efficiency and effectiveness of business processes.

Mobility solutions can be used for end-to-end automation of field-based processes and for the capture of accurate and detailed data on the condition of network assets:

- Mobile solutions can support job assignment, physical asset information and job instructions for reactive and planned tasks;
- Mobile workforce technology can enable more efficient field services from a workforce, asset management and customer service perspective; and
- Mobile devices can become a key information management tool for the timely transfer of field and asset information between field works, back-office systems and customers.

Our customers will directly benefit from increased use of Mobility solutions by our service providers with service orders being addressed in a more timely and efficient manner as a result of field technicians having direct mobile access to the latest information relating to each call.

In the 2016 to 2020 period, we will implement systems to:

- Dispatch fault details from the Distribution Management System (DMS) directly to Mobile devices held by field service providers; and
- Implement scheduling and planning capabilities for Fault Despatch and Works Planning in our IT systems for use by service providers.

While these projects are a key element of our IT capex program for 2016 to 2020, they are primarily required to improve cost efficiency and delivery reductions in operations costs. Therefore no additional capex has been included in our EDPR submission as these projects would be funded by us through reductions in business opex or a reallocation of network capex.

4.6. Improve asset planning and management through analytics and reporting

During the 2016 to 2020 period, we will extend our real time analytics with the capture and utilisation of incremental smart metering data to underpin the distribution business model. These initiatives will undertake incremental development to extend the firmware within the meter to AMI head-end to capture instantaneous current, voltage and power factor data to feed engineering analytics.

In the 2016 to 2020 period, we will implement systems to:

- Provide the capability to analyse real-time data of current feeder loads to remotely reconfigure loaders for load balancing and loss minimization; and
- Implement improved analysis of real-time data to proactively optimise asset utilisation and identify energy theft.

The cost of these projects to improve asset planning and management through analytics and reporting is forecast at $12.66 million (all SCS) over the 2016 to 2020 period.

4.7. Maintain Systems at Industry Standard – Recurrent Expenditure

We have made a significant investment in new IT systems over the last ten years. During 2006 to 2010, investment was focussed on the need to deliver systems to support the AMI deployment. This was largely funded under AMI CROIC. Focus in the subsequent period was on the replacement of several of our core business systems.

We must now maintain these systems to reduce risk of business disruption and retain levels of efficiency.

IT systems lifecycle refresh is a recurring cost which covers:

- Licence fees and implementation costs to maintain application software at a version which, in line with our “IT Asset Management Policy”, is fully supported and maintained by the software supplier; and
- Purchase and implementation costs to refresh hardware, firmware and systems software (such as operating systems, communications and database software) to versions that, in line with our “IT Asset Management Policy” are fully maintained and supported by the relevant supplier.

Failure to maintain IT systems properly would create business risk to our operation. Supplier support in the event of incidents and problems would be limited and may even be withdrawn. This creates a risk to system reliability, performance and availability. These in turn present a risk to business operations and compliance with regulatory obligations.

Recurring expenditure on maintaining IT systems at industry standard makes up over 60% of the planned IT capital expenditure for the period (excluding the provision for regulatory change). We carefully consider lifecycle refresh requirements, risks and options as part of our Project Delivery Methodology.

Key projects for 2016 to 2020 include lifecycle refreshes of:

- Distribution Management System (DMS) used to maintain network reliability and control the network particularly during planned and unplanned outages;
- Geographic Information System (GIS) including GE Smallworld and associated software FME (Feature Manipulation Engine), GIS Connect (SAP / GIS integration);
- Customer Management and Billing and Enterprise Resource Planning (SAP) through continuing application of SAP enhancement packs; and
- Shared Storage, Intel Servers, Data Network and Pinewood data centre hardware and operating level software.

In addition, we will operate an ongoing program of minor application refreshes to maintain systems at industry standard. This program is carried out under a single capital project entitled 'Small Applications Lifecycle refresh'.

The recurrent expenditure required to maintain our systems at industry standard is forecast to be $68.81 million ($60.69 million SCS and $8.12 million ACS - metering) over the 2016 to 2020 period.

The following section provides further details of these programs.

5. Expenditure Forecasts and Timings for the Forthcoming Period

This section presents an overview of our Non-Network ICT Capital program and the timing of expenditure for the 2016 to 2020 period, at a total IT capital cost of $180 million.

5.1. Overview

Of these 41 projects proposed for the next regulatory period:

- 22 projects are identified as recurrent expenditure at a value of $68.8 million, and are required to maintain the currency and/or capability of our IT infrastructure, applications and services over the next regulatory period; and
- 19 are non-recurrent at a value of $111.2 million, required to meet regulatory requirements, identify and deliver customer benefits and provide improved and/or new functionality that supports the business in delivering asset management distribution network efficiencies.

This is summarised in Table 5.

Table 5 Our forecast ICT capex by expenditure category for the next regulatory period

Expenditure Category	Summary of Projects	Cost $m
Recurrent Expenditure	22 projects relating to maintaining the currency and/or capability of our IT infrastructure, applications and services (including refreshment of our client device fleet over the 2016-20 period)	$68.8 million
Non-Recurrent Expenditure	19 projects that deliver new and/or enhanced capability to meet customer / business needs. Of these: • Ten are projects that meet a regulatory requirement or rule change (9 for Power Of Choice and 1 for RIN reporting) • Nine are projects to meet a customer/business requirement	$111.2 million $69.7 million $41.4 million

5.2. Recurrent Expenditure

Recurring expenditure on maintaining IT systems at industry standard makes up over 60% of the planned IT capital expenditure for the period (excluding the provision for regulatory change). We carefully consider lifecycle refresh requirements, risks and options as part of our Project Delivery Methodology.

The need and frequency of an IT system lifecycle refresh are determined for each system by a range of factors including:

- The criticality of the system to business operation (i.e. if the system fails what is the risk to the business of not having an operational system and for how long is the business prepared to sustain that risk);
- The physical (hardware) asset life (noting that replacing hardware assets often requires software assets to be upgraded as they may no longer be compatible with the newer hardware); and
- The level of integration of the IT system, generally the greater the integration with other systems the greater the risk of failure of the system or those integrated with it if it is not refreshed in a timely manner.

IT systems lifecycle refresh is a recurring cost which covers:

- Licence fees and implementation costs to maintain application software at a version which is fully supported and maintained by the software supplier (current version); and

- Purchase and implementation costs to refresh hardware, firmware and systems software (such as operating systems, communications and database software) to versions that are fully maintained and supported by the relevant supplier.

Table 6 outlines UE's proposed annual recurrent ICT capex projects for the next regulatory control period, the main driver of which is to maintain systems to industry standard, consistent with section 6.5.7 of the National Electricity Rules.

Table 6 Our proposed ICT capex projects for the next regulatory control period – Recurrent

Key Driver and Outcome	Projects	Regulatory requirement met	ACS/SCS/ Total	2016 ($M)	2017 ($M)	2018 ($M)	2019 ($M)	2020 ($M)	Total
Maintain systems to industry standard	• Application Change Requests (Factory) • SCADA refresh • Infrastructure Refresh Program – Reporting Platform • Infrastructure refresh – Data protection • Infrastructure refresh – Client Device Lifecycle • Infrastructure Refresh - Telephony • Lifecycle refresh of the Distribution Management System (DMS) • SSN UIQ lifecycle refresh • SAP ERP ISU lifecycle refresh • GIS Refresh • SAP – CRM refresh • Itron Lifecycle Refresh • WebMethods Refresh • Security Program • SAP Data Archiving • Itron Data Archiving • SEMS refresh • Small applications refresh • EDMS refresh • Vault environment refresh • Meter asset management • IT infrastructure refresh	• NER 6.5.7 (a) (3) (iii) maintain the quality, reliability and security of supply of standard control services • NER 6.5.7 (a) (3) (iv) maintain the reliability and security of the distribution system through the supply of standard control services • NER 6.5.7 (a) (4) maintain the safety of the distribution system through the supply of standard control services.	ACS SCS Total	$1.22 $4.08 $5.30	$2.82 $16.19 $19.00	$0.42 $6.65 $7.07	$0.82 $12.63 $13.45	$2.85 $21.14 $23.99	**$8.12** **$60.69** **$68.81**

5.3. Non-recurrent Expenditure

The key drivers that sit behind non-recurrent expenditure includes the requirements to:

- Meet regulatory requirements, specifically Power Of Choice and RIN Reporting;
- Identify and deliver customer benefits, more specifically aimed at providing and supporting better customer interaction; and
- Provide improved and/or new functionality that supports the business in delivering a range of benefits (e.g. asset management efficiencies such as deferred network capital expenditure, and distribution network efficiencies).

Table 7 outlines UE's proposed annual non-recurrent ICT capex projects for the next regulatory control period categorised against our key strategic drivers which are to:

- Meet customers' changing needs and expectations;
- Ensure ongoing performance, safety and resilience of the changing, more complex distribution network;
- Automate end-to-end processes to support field service providers;
- Ensure readiness to meet regulatory requirements;
- Improve efficiency of asset management and across the business; and
- Maintain systems to industry standard, consistent with section 6.5.7 of the National Electricity Rules.

Table 7 Our proposed IT capex projects for the next regulatory control period – Non-recurrent

Key Driver and Outcome	Projects	Regulatory requirement met	ACS/SCS/ Total	2016 ($m)	2017 ($m)	2018 ($m)	2019 ($m)	2020 ($m)	Total
Deliver new capabilities to meet changing customer needs and expectations	• Effortless customer experience (Portal) • Effortless customer experience (CRM)	• NER 6.5.7 (a) (1) meet or manage the expected demand for standard control services over that period • NER 6.5.7(e) the extent to which the capital expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers;	ACS SCS Total	$0 $2.00 $2.00	$0 $1.85 $1.85	$0 $0 $0	$0 $0 $0	$0 $0 $0	**$0** $3.85 $3.85
Ensure ongoing performance, safety and resilience of the changing, more complex distribution network	• Network Real Time Analytics – Neutral Integrity • DMS Feeder load management • DMS LV management • Secondary Equipment Management System (SEMS) refresh OMS smart grid gateway extensions	• NER 6.5.7 (a) (3) (iii) maintain the quality, reliability and security of supply of standard control services • NER 6.5.7 (a) (3) (iv) maintain the reliability and security of the distribution system through the supply of standard control services • NER 6.5.7 (a) (4) maintain the safety of the distribution system through the supply of standard control services.	ACS SCS Total	$0 $1.79 $1.79	$0 $3.61 $3.61	$0 $6.11 $6.11	$0 $5.49 $5.49	$0 $4.58 $4.58	**$0** $21.58 $21.58
Automate end-to-end processes to support field service providers	• Asset data collection	• NER 6.5.7 (c) (1) the efficient costs of achieving the capital expenditure objectives • NER 6.5.7 (c) (2) the costs that a prudent operator would require to achieve the capital expenditure objectives	ACS SCS Total	$0 $0 $0.00	$0 $0 $0.00	$0 $3.38 $3.38	$0 $0 $0.00	$0 $0 $0.00	**$0** **$3.38** $3.38

Table 8 Our proposed IT capex projects for the next regulatory control period – Non-recurrent - continued

Key Driver and Outcome	Projects	Regulatory requirement met	ACS/SCS/ Total	2016 ($m)	2017 ($m)	2018 ($m)	2019 ($m)	2020 ($m)	Total
Ensure readiness to meet regulatory requirements	• Demand response mechanisms • Multiple trading relationships • Network pricing • Metering competition • Customer transfer system • Customer access to metering data • RIN Reporting • Demand Mgt – AEMO reporting • Demand Mgt – IT Platform • Embedded Networks • NECF	• NER 6.5.7 (a) (2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services (which in this case refer to the "Power of choice" regulatory changes).	ACS SCS Total	$6.18 $22.83 $29.01	$2.06 $21.43 $23.49	$0 $17.28 $17.28	$0 $0 $0.00	$0 $0 $0.00	**$8.24** **$61.54** $69.78
Improve efficiency of asset management and across the business	• Enterprise project and portfolio management • Asset management system capability project	• NER 6.5.7 (a) (3) (iii) maintain the quality, reliability and security of supply of standard control services • NER 6.5.7 (c) (1) the efficient costs of achieving the capital expenditure objectives • NER 6.5.7 (c) (2) the costs that a prudent operator would require to achieve the capital expenditure objectives	ACS SCS Total	$0 $0 $0.00	$0 $1.85 $1.85	$0 $3.6 $3.60	$0 $3.6 $3.60	$0 $3.6 $3.60	**$0** **$12.66** $12.66

6. Meeting Rules' requirements

This section explains and justifies United Energy's reinforcement capital expenditure forecast against the capital expenditure objectives, criteria and factors defined in the NER.

It therefore outlines why the AER should approve this ICT capital expenditure forecast as part of its distribution determination for us in the forthcoming regulatory control period.

6.1. The capital expenditure objectives

The National Electricity Rules (NER) set out the objectives that the proposed capital expenditure for the forthcoming regulatory control period is required to achieve (Table 9).

Table 9 - Clause 6.5.7(a) of the National Electricity Rules (NER)

Clause 6.5.7(a) is:

(a) A *building block proposal* must include the total forecast capital expenditure for the relevant *regulatory control period* which the *Distribution Network Service Provider* considers is required in order to achieve each of the following (the *capital expenditure objectives*):

(1) meet or manage the expected demand for *standard control services* over that period;

(2) comply with all applicable *regulatory obligations or requirements* associated with the provision of *standard control services*;

(3) to the extent that there is no applicable *regulatory obligation or requirement* in relation to:

(i) the quality, reliability or security of supply of *standard control services*; or

(ii) the reliability or security of the *distribution system* through the supply of *standard control services*,

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of *standard control services*; and

(iv) maintain the reliability and security of the *distribution system* through the supply of *standard control services*; and

(4) maintain the safety of the *distribution system* through the supply of *standard control services*.

Our ICT assets are integral to our business operations. ICT systems support almost all of our core business functions (as shown in Section 1, Table 1). Without on-going investment to maintain and refresh our ICT assets, we will not be able to deliver our core network services. We would not be able to operate our business effectively, continue to meet the information needs of our customers, achieve the required system availability and performance levels required by customers or meet future industry and regulatory challenges.

The table in the previous section shows how the expenditure addresses these specific rules requirements for each of our ICT capex categories.

The ICT capital expenditure that we propose therefore meets the capital expenditure objectives as defined in clause 6.5.7(a).

6.2. Capital expenditure criteria

The NER set out the expenditure criteria that are relevant to our ICT capital expenditure forecast for the forthcoming regulatory control period.

Table 10 - Clause 6.5.7(c) of the National Electricity Rules (NER)

Clause 6.5.7(c) is: (c) The *AER* must accept the forecast of required capital expenditure of a *Distribution Network Service Provider* that is included in a *building block proposal* if the *AER* is satisfied that the total of the forecast capital expenditure for the *regulatory control period* reasonably reflects each of the following (the *capital expenditure criteria*): (1) the efficient costs of achieving the capital expenditure objectives; (2) the costs that a prudent operator would require to achieve the capital expenditure objectives; and (3) a realistic expectation of the demand forecast and cost inputs required to achieve the *capital expenditure objectives*.

We have achieved each of these criteria in relation to our ICT capital expenditure forecast:

- The scope of our IT capex program has been defined following a robust planning process governed by an executive-level governance group (see Appendix B);
- Our total ICT costs for the forthcoming period would have been lower than the two previous periods were it not for the costs of meeting the Power of Choice and RIN reporting regulatory requirements and expectations (see Appendix A);
- Our ICT costs are in line with industry benchmarks (when assessed on a like-for-like basis) – see Section (see Appendix A)
- We have a solid track record of delivering projects effectively and efficiently as demonstrated by the successful delivery of our major core system replacement program in the current period (see Appendix A)
- Our forecasts unit costs for labour (approximately 76% of the total cost) are largely based on rates defined in master services agreements with our panel of external systems integration service providers selected following a competitive procurement process (see Appendix C);
- Our forecast unit costs for hardware are based on rates derived from quotes and contracts obtained through competitive procurement processes (see Appendix C);
- Our cost estimates for recurrent expenditure are largely based on our prior actual expenditure on similar projects (see Appendix C); and
- Our IT capex is closely monitored and controlled through our project delivery framework approach which places strict controls on projects through project monitoring and decision-making processes (see Appendix B).

6.3. Capital expenditure factors

The NER set out the capital expenditure factors to which regard must be had in considering United Energy's reinforcement capital expenditure forecast for the forthcoming regulatory control period.

Table 11 - Clause 6.5.7(e) of the National Electricity Rules (NER)

Clause 6.5.7(e) is:

(e) In deciding whether or not the AER is satisfied as referred to in paragraph (c), the AER must have regard to the following (the capital expenditure factors):

- (1) [Deleted]
- (2) [Deleted]
- (3) [Deleted]
- (4) the most recent annual benchmarking report that has been published under rule 6.27 and the benchmark capital expenditure that would be incurred by an efficient Distribution Network Service Provider over the relevant regulatory control period;
- (5) the actual and expected capital expenditure of the Distribution Network Service Provider during any preceding regulatory control periods;
- (5A) the extent to which the capital expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers;
- (6) the relative prices of operating and capital inputs;
- (7) the substitution possibilities between operating and capital expenditure;
- (8) whether the capital expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8A or 6.6.2 to 6.6.4;
- (9) the extent the capital expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms;
- (9A) whether the capital expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b);
- (10) the extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives; and
- (11) any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s):
- (12) any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is a capital expenditure factor.

The way that our ICT capex proposal addresses the capital expenditure factors is presented in Table 12.

Table 12 – How we address the capital expenditure factors

Capital Expenditure Factors		How addressed in our ICT proposal
(4)	**Benchmarking**	• Benchmarking of our overall business costs are set out in the Regulatory Proposal. Benchmarking of ICT capex is set out in Appendix A.
(5)	**Actual and expected expenditure in previous periods**	• The year-by-year actual and forecast ICT expenditure for the 2011 to 2015 period is set out in Section 3 as is the forecast ICT expenditure for the 2016 to 2020 period. Further detail on the expenditure in the 2011 to 2015 period is set out in Appendix A.
(5A)	**Concerns of electricity customers**	• Our process to identify the concerns of electricity customers is outlined in the Regulatory Proposal. Our approach to meeting these concerns from an ICT perspective is set out in Section 4.2.
(6)	**Relative prices**	• The basis of the rates used as inputs to our forecasts are set out in Appendix C. Further details are set out in the IT Capital Plan document and in the cost model.
(7)	**Substitution between opex and capex**	• Substitution possibilities between opex and capex (particularly the potential use of cloud computing) have been assessed on a project-by-project basis in individual project justification documents. The use of cloud will again be considered when projects are initiated and full business cases are developed.
(8)	**Consistency with incentive schemes**	• Not applicable.
(9)	**Not reflecting arm's length terms**	• All of our forecast expenditure will be incurred with external commercial entities on full arm's length terms.
(9A)	**Contingency Projects**	• Not applicable.
(10)	**Provision for efficient and prudent non-network alternatives**	• ICT can be an alternative to network expenditure as set up in Section 4.3.
(11)	**Project Assessment Reports**	• Not applicable.
(12)	**Other factors notified by AER**	• None identified.

6.4. Building block requirements

The NER set out matters that United Energy's building block proposal must contain in relation to reinforcement capital expenditure.

Table 13 - Clause S6.1.2 of the National Electricity Rules (NER)

Clause S6.1.2 is:

A *building block proposal* must contain at least the following information and matters relating to capital expenditure:

(1) a forecast of the required capital expenditure that complies with the requirements of clause 6.5.7 and identifies the forecast capital expenditure by reference to well accepted categories such as:

- (i) asset class (eg. *distribution lines*, *substations* etc); or
- (ii) category driver (eg. *regulatory obligation or requirement*, replacement, *reliability*, net market benefit, business support etc),

and identifies, in respect of proposed material assets:

- (iii) the location of the proposed asset;
- (iv) the anticipated or known cost of the proposed asset; and
- (v) the categories of *distribution services* which are to be provided by the proposed asset;

(2) the method used for developing the capital expenditure forecast;

(3) the forecasts of load growth relied upon to derive the capital expenditure forecasts and the method used for developing those forecasts of load growth;

(4) the key assumptions that underlie the capital expenditure forecast;

(5) a certification of the reasonableness of the key assumptions by the directors of the Distribution Network Service Provider;

(6) capital expenditure for each of the past regulatory years of the previous and current regulatory control period, and the expected capital expenditure for each of the last two *regulatory years* of the current *regulatory control period*, categorised in the same way as for the capital expenditure forecast and separately identifying for each such *regulatory year*:

- (i) margins paid or expected to be paid by the Distribution Network Service Provider in circumstances where those margins are referable to arrangements that do not reflect arm's length terms; and
- (ii) expenditure that should have been treated as operating expenditure in accordance with the policy submitted under paragraph (8) for that regulatory *year*;

(7) an explanation of any significant variations in the forecast capital expenditure from historical capital expenditure; and

(8) the policy that the *Distribution Network Service Provider* applies in capitalising operating expenditure.

The way that our ICT capex proposal addresses the building block requirements is presented in Table 14.

Table 14 – How we address the building block requirements

Building Block Requirements		How addressed in our ICT proposal
(1)	**Forecast that complies with clause 6.5.7**	• The compliance of our forecast with clause 6.5.7 is outlined in Section 6.3.
(2)	**Method used**	• The method used to prepare the forecast is set out in Appendix C of this document and in further detail in the IT Capital Program document.
(3)	**Growth forecasts**	• Drivers for ICT expenditure are as set out in Section 4.1.
(4)	**Key assumptions**	• Key assumptions are outlined in the Regulatory Proposal.
(5)	**Directors' certification**	• The Directors' certification is contained in an Appendix to the Regulatory Proposal.
(6)	**Year-by-year breakdown of capital expenditure with details of arm's length terms and operating expenditure**	• The year-by-year actual and forecast ICT expenditure for the 2011 to 2015 period is set out in Section 3 as is the forecast ICT expenditure for the 2016 to 2020 period. Further detail on the expenditure in the 2011 to 2015 period is set out in Appendix A.
(7)	**Significant variations from historical expenditure**	• The trends and variations in forecast vs historical expenditure is set out in Appendix A.
(8)	**Capitalisation policy**	• There has been no change to the policy that applies in the current period.

7. Supporting documentation

The following documents support United Energy’s IT capex program for the next regulatory control period.

- IT Capital Program 2016 to 2020
- Utilities ICT Benchmarking Study for United Energy and Multinet Gas, KPMG

Appendix A: Current period expenditure and outcomes

This section explains that we have incurred a minor overspend to our IT capex in the current regulatory control period compared with the capex plan presented to the AER in our regulatory proposal, as well as the AER's own capex allowance in its distribution determination. It explains the relatively minor variations that occurred and the way in which these variations were governed.

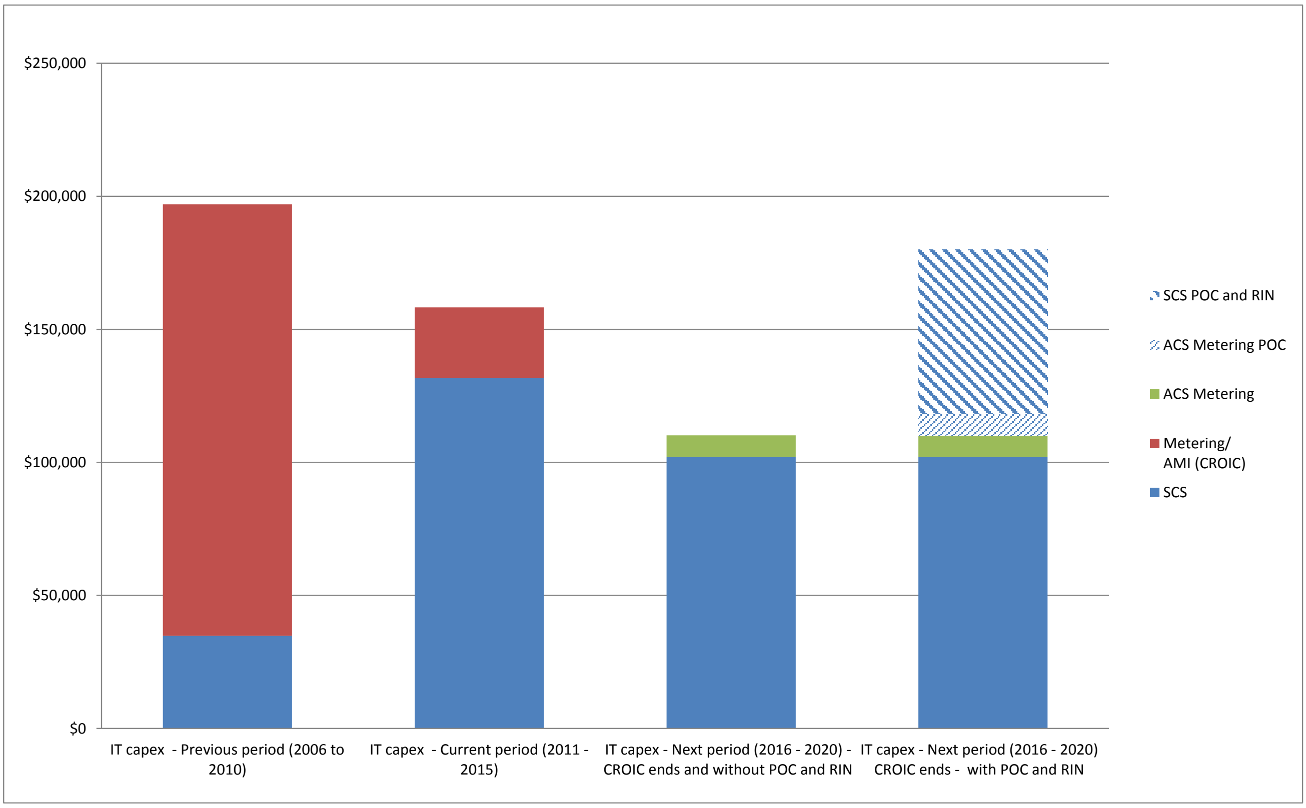
A1: Background to our IT Capital Expenditure

Figure 15 shows the trends in our IT capital expenditure over three regulatory periods. This figure shows that in the five-year period prior to 2011, capital expenditure in IT was dominated by the demands of the AMI program and expenditure on non-AMI IT systems was limited. In the 2006 to 2011 period, we underspent on IT SCS capex. Our actual expenditure for that period was approximately 50% of the forecast spend in our regulatory submission.

This lack of investment on many of our core systems prior to 2011 presented a commercial and technical risk to UE. Core systems were, in many cases, end of life and presented a risk to ongoing operations. In addition, the poor state of our IT systems presented a barrier to the achievement of our plans to transform our business model.

Having completed the AMI IT program by 2011, our IT capital program for the current period (2011 to 2015) was therefore focussed on the replacement of several core systems. This core-systems replacement program was described in the our IT Capital Plan for 2011 to 2015 which was presented as part of our EDPR submission in 2009. As a result, the AER allowance for the current (2011 to 2015) period was $125.8million; an increase of $45.6million (or 57%) over the allowance for the previous period.

Figure 15 Trends in ICT Capex over three regulatory periods



A2: Actual expenditure versus AER allowance for the Current Period (2011 to 2015)

Table 16 current period expenditure ($2015M)

	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Estimated	Total Estimated	Variance Estimated
United Energy expenditure	56.14	14.48	11.97	24.27	24.35	131.20	5.39 (overspend)
AER allowance	26.70	41.44	31.29	18.19	8.18	125.81	

Our actual / estimated ("actual") IT capex during the current regulatory control period is estimated to be $131.20 million – a minor overspend of 4.3%. This minor overspend allowed us to:

- Implement CRM capability for claims and complaints processing which can be leveraged for our 'effortless customer experience' program in the forthcoming period; and
- Increase our ability to better leverage a mobile solution to support improved asset management, safety and regulatory reporting.

Our transformation to a new business operating model in which core strategic functions were brought in house while other functions are outsourced, has delivered significant benefits. The Australian Energy Regulator's annual benchmarking report indicates that we are one of the most efficient distributors nationally across a variety of measures. The successful replacement of our core IT systems over the 2011 to 2015 period was critical for the success of the transformation and the resulting benefits.

Our IT investment during this period, together with our transformation to the new business model, has achieved the planned benefits to our company and our customers. The investment has:

- Implemented a suite of foundation systems that provides a robust platform for us to meet our future customer, business and regulatory requirements;
- Removed all dependence on the IT capability of Jemena Asset Management (JAM);
- Consolidated and rationalised legacy applications;
- Enabled us to reduce our overall business operating costs by transforming our business operating model;
- Implemented systems to provide a foundation to meet regulatory reporting requirements;
- Consolidated AMI systems with other corporate systems; and
- Achieved operational cost reductions through more efficient outsourcing of IT support services to commercial service providers.

Table 17 presents the status of the key IT projects listed in the 2009 IT Capital Program Review document which formed the basis for the 2011 to 2015 EDPR submission. This table shows that with the implementation of the remaining systems by 2015, We will have completed the key projects within the program of work for 2011 to 2015.

Table 17 Current Status of Key IT Projects listed in our 2009 IT Capital Program3

Project	Status
ERP – SAP Consolidation	Complete
CIS Migration of Legacy Meters	Underway – on track to be completed by end 2015
SCADA Replacement	Underway - on track to be completed by end 2015
DMS Upgrade	Underway - on track to be completed by end 2015
Identity and Access Management System	Complete
Market System Upgrade (CATS / B2B)	Complete
System Rationalisation and Consolidation	Complete
Enterprise Content Management System	Initial phases complete. Remainder to be complete by end 2015
New Disaster Recovery Data Centre Implementation	Complete
New Production Data Centre Implementation	Complete

A3: Benchmarking

Benchmarking our costs against our peers allows us to assess the efficiency of our business, and identify areas for improvement.

Benchmarking of our overall business costs shows that we benchmark favourably against our peers. For example, the AER's benchmarking shows that we have the lowest asset cost per customer of any DNSP in the NEM. We have the highest utilised network in Australia. The benchmarking demonstrates that our new business model is efficient. Our customers are benefiting from this through lower network prices.

In 2013, KPMG undertook a Utilities ICT Benchmarking Study for United Energy and Multinet Gas that looked at our organisation and ICT performance, investment and operating activities for the financial year 2012 and 2013, focusing on:

- Corporate ICT benchmarks - compared the participants ICT investments and operations at enterprise level;
- DNSP benchmarks – compared the participants ICT investments for the participants regulated electricity or natural gas network businesses; and
- AMI benchmarks – compared the AMI roll-out programs of the 3 Victorian participants.

The participants group comprised 10 energy DNSPs from across Australia, including UE and MG and:

- Ausgrid (NSW)
- Endeavour Energy (NSW)
- Essential Energy (NSW)
- Energex (QLD)
- Ergon Energy (QLD)
- SA Power Networks (SA)
- Western Power (WA)
- SP Ausnet (VIC)

3 UED IT Capital Program Review, November 2009 p7.

- Jemena (VIC)

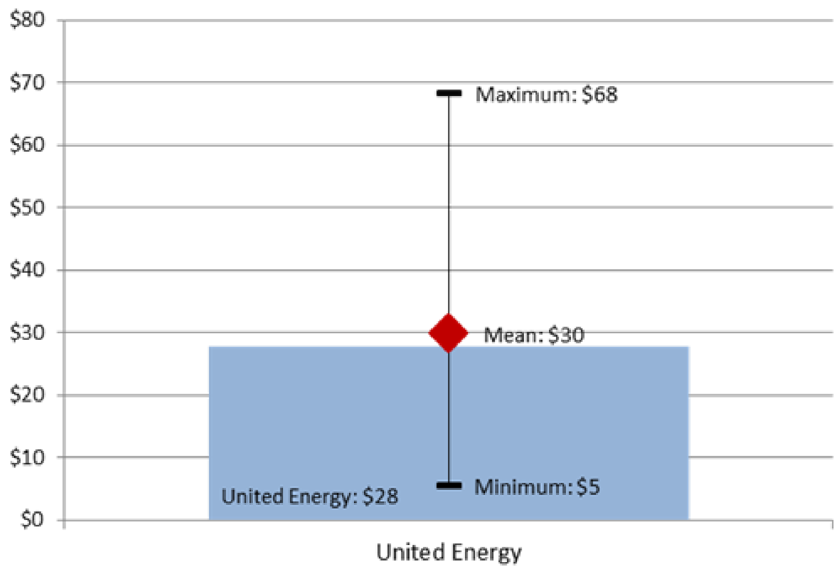
Our results in the 2013 KPMG Utilities IT Benchmarking reflected our investment timing, and expenditure management when compared to the benchmarking group.

The KPMG non-network ICT expenditure benchmarks of the 10 DNSPs, excluded each DNSP's Regulatory and AMI ICT expenditures, to ensure consistency in the comparison of the benchmarking group.

The non-network ICT capex benchmarks compare the average annual non-network ICT capex of the benchmarking group for 5 years from 2008 to 2012.

Our average annual non-network ICT capex (recurrent and non-recurrent) per customer at $28 per customer is just below the benchmark average of $30 per customer, the result shows that our ICT capex investment over the five year period, brings our ICT capex per customer to a level comparable to the benchmark group.

Figure 18 Average annual non-network ICT capex (recurrent and non-current)



Overall, our results in the 2013 KPMG benchmarking reflect the increasing trend of ICT capex investments in the current regulatory period, the increases brought United Energy from its under invested ICT landscape and capex to comparable industry level.

On a like-for-like basis (excluding AMI-related expenditure and external regulatory requirements) our IT capex for the forthcoming period will be $29 per customer p.a. which is still below the current industry mean of $30 per customer p.a).

Appendix B: Management and Governance of the Program

B1: Deliverability

In the current period, we have successfully delivered a challenging IT capital program, including several large IT projects that were critical to our business transformation. We implemented a major ERP replacement project, a system separation project, two data centre relocations, a major infrastructure refresh, updates of the distribution management system and upgrades of market systems.

The scope of the IT program and the projects completed were closely aligned to the IT Capital Plan presented to the AER five years ago. Where changes and reprioritisations to the program were necessary, these were managed through a robust IT governance structure. The IT systems implemented in the current period provide a sound foundation for the delivery of further projects in the next regulatory period.

We are well positioned to deliver the IT projects described in this document as a result of:

- Our established panel of external IT systems implementation service providers and our track record of successfully delivering projects using those service providers;
- Our proven IT project delivery framework (outlined below); and
- Our robust IT governance structure (outlined below).

The success of the IT program in the current regulatory period shows that we are well positioned to deliver the proposed program in the forthcoming period.

The proposed IT Capital Program will enable us to meet the needs of our customers by maintaining systems at industry standard, addressing current gaps in functionality, meeting regulatory requirements and addressing future business challenges and opportunities.

B4: IT Operating Model

In accordance with our overall business operating framework, our IT group is relatively small with around 20 full-time employees managing IT projects and services. This IT group:

- Develops and maintains an IT strategy and architectural framework that facilitates the implementation of the business strategy and ensures that risk is effectively managed;
- Scopes and delivers a portfolio of projects that facilitates the implementation of business and IT strategies;
- Manages the relationship between IT customers and service providers and ensures that services are cost effectively aligned with business priorities; and
- Provides cost-effective IT services that enable both ourselves and our field service providers to deliver and continually improve operational services.

Our IT systems operations are fully outsourced to commercial service providers that were engaged following formal competitive procurement processes. This ensures the provision of system operations at the most efficient cost and the best outcome for customers.

IT projects are carried out by a panel of external service providers. The panel was formed on the basis of a formal procurement process. We follow a process in which, at the start-up phase of each project, formal quotations are requested from two or more of the service providers on our panel. Work is then commissioned under rates and commercial mechanisms defined when the panel was established. In some cases, service provider resources will be supplemented with our staff and/or other contract resources.

We have established a specific contract with a commercial service provider for smaller projects and enhancements to existing systems.

Our IT Operating Model provides us with access to leading IT expertise at competitive rates. The model provides us with the flexibility to bring on resources as required to meet fluctuating patterns of project demand.

B5: IT Governance Framework

Our IT governance structure provides oversight, guidance and direction to its IT capex program. A high-level committee, including key members of our executive, meets monthly to approve new projects, track and monitor existing projects and ensure overall alignment of IT expenditure with business, customer and regulatory requirements.

We will continue to operate a robust IT governance framework over the next EDPR period. Currently, our IT governance framework consists of the following joint business IT governance and advisory groups:

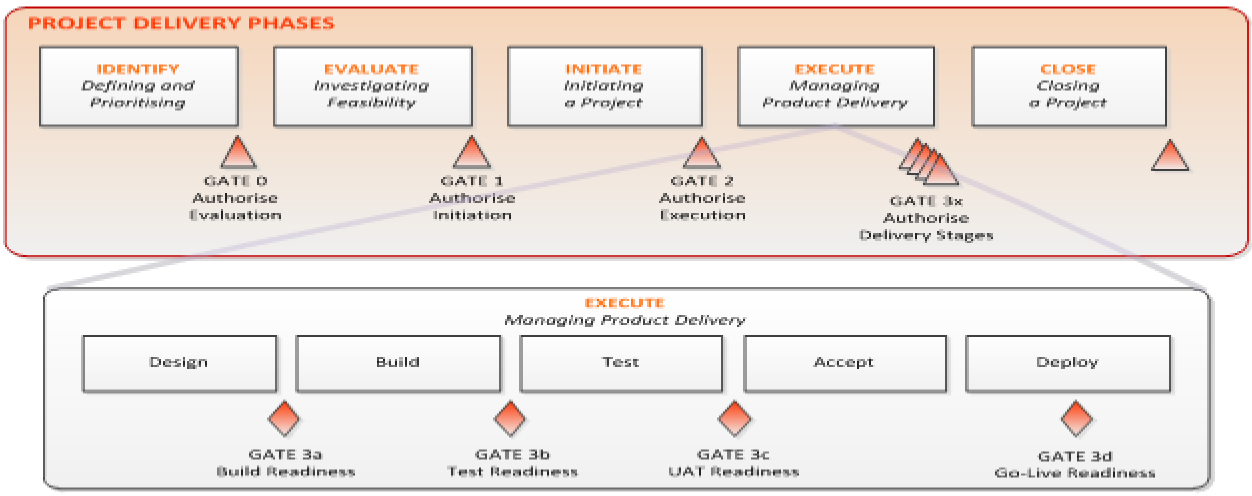
- IT Executive Forum – the peak IT governance forum in which our executive management team (including the CEO) oversees all IT capital investment and ensures that IT investment is aligned with business strategies and priorities;
- IT Architecture Review Board - ensures that proposed solutions are aligned with business and IT architectural requirements and total cost of ownership considerations;
- Information Security Management System (ISMS) Governance Group - oversees the implementation of the ISMS across business and IT functions;
- Project Steering Committees - established for all major projects; and
- Application Change Control Board - approves and prioritises small enhancements and business change requests.

Our IT Capital Plan has been reviewed and approved by the IT Architecture Review Board and by the IT Executive Forum. Security aspects of the plan have been reviewed and endorsed by the Information Security Management System (ISMS) Governance Group.

B6: Project Delivery Framework

Project management processes and guidelines define delivery management processes and standards to ensure a consistent approach to delivering IT programmes and projects within UE and MG (Figure 19).

Figure 19 Our IT Project Delivery Framework



The standard approach for program and project management enables effective engagement of appropriate stakeholders in governance, management review and decision making and ensures that:

- Project delivery management activities are focussed on achieving the investment value proposition (business case) and satisfying specific project objectives (requirements, risk, costs, schedule and quality) to deliver required business outcomes;
- The scope of the work to be accomplished is formalised, and products/deliverables identified that will satisfy the project objectives and deliver value;
- A formal, approved, integrated project plan guides project execution and control throughout the life of the project;
- Baselines are defined and established to enable effective monitoring and control of the utilisation of organisational resources on a programme and/or project, and to identify deviations from the expected and respond to exceptions.;
- Controls are established to ensure product quality, and project effectiveness including compliance with standards and performance against plan; and
- Project stakeholders ascertain whether the project, release or iteration delivered the planned results and value .at the end of each project, release or iteration.

Our Project Delivery Framework also defines an approach for the management of benefit realisation. Our benefit realisation approach requires:

- Early identification of Solution benefits at the ‘identify’ phase;
- Production of a Benefits Realisation Plan (BRP) at the ‘evaluate’ stage; and
- Development of a Benefits Realisation Register to be handed over at project closure.

The Benefits Realisation Plan (BRP) is used to define how and when a measurement of the achievement of the project’s benefits, expected by the Business Owner, can be made. The Plan is presented to the Executive during the ‘Initiating a Project’ phase, updated at the completion of each phase, and used during the ‘Closing a Project’ phase to define any post-project benefits reviews that are required.

The plan is required to cover activities which will determine if the expected benefits of the project have been realised and how the solutions have performed in operational use. The level of achievement of benefits is assessed together with any additional time needed to realise the residual benefits.

Appendix C: Expenditure forecasting method for forthcoming period

This section provides an overview of our forecasting methodology for IT capex for the next regulatory control period and explains why United Energy considers that it is the most reasonable methodology for regulatory forecasting. Further detail of this forecasting method is found in the IT Capital Program document.

C1: Project Justification Documentation

Our IT Project delivery methodology (Project Development Framework) defines our requirements for the documentation that is required before any project can proceed and that expenditure is approved. This documentation includes a project Business Case. Typically a Business Case is prepared as part of the initial stages of a project.

The AER has requested that 'Business Cases' be available for IT projects included in our regulatory submission. However it is not efficient or practicable to develop detailed project approval documentation several years in advance of the initiation of a project. The investment to develop full business cases would be substantial and would not necessarily increase the accuracy of estimates as information technology costs can vary significantly over time as new products and solutions become available.

To meet the AER's requirement we have created a high-level project expenditure document for each project in our IT Capital Program. This document presents details about the objectives and scope of the project, the reasons why the project is justified and the basis of the cost estimate.

Two forms of the high-level project expenditure document have been used depending on the materiality and level of justification required for a given project as follows:

- **Project Overview** – a 1 to 2 page document that provides a high level description, justification and estimate, has been produced for projects that are forecast to be less than $2M in capital expenditure and/or recurrent projects for which justification for the expenditure is considered straightforward (e.g. a system lifecycle refresh project) and where estimates are generally based on actual expenditure from similar previous projects; and
- A **Project Justification** – a 5 to10 page document that provides a more detailed description, justification and estimate, have been produced for projects that are forecast to be in excess of $2M.

The Project Overview and Project Justification documents:

- Provide a description of the project;
- Document alignment to our business and IT strategies;
- Describe the impact of not proceeding with the project "Do Nothing" and the viable alternative solutions that were considered (e.g. Cloud vs in-house);
- Present, particularly for non-recurrent projects, the project's business benefit; and
- Present the proposed solution including the rationale for recommending this solution, approximate timing for delivery of the project and the forecast expenditure that will be incurred implementing the solution.

C2: Forecasting Method Overview

Our IT capex forecast was based on a combination of top-down and bottom-up expenditure forecasting approaches. We considered the business as usual expenditure and then set a goal of reducing this in real terms. To achieve this, we assessed the various categories of expenditure top-down and considered where efficiencies could be achieved (e.g. in IT infrastructure refresh). We then used bottom-up forecasting as described to confirm and support top-down forecasting.

Much of the recurrent investment results directly from our need to maintain our systems at industry standard. In assessing the requirement for recurrent investment, we take into account a range of factors including:

- The age profile of the equipment;
- Vendor support policies;
- Planned variations in employee numbers;
- Fault rates; and
- New and prevailing technologies.

Other investment requirements were identified through an ongoing process of business consultation, seeking feedback from customers and other stakeholders and assessing technological developments which could provide performance and operational efficiencies..

High-level Project Overviews or Project Justifications were prepared for each proposed project. The detail contained in, and supporting, the Project Overview/Justification was sufficient to determine whether the proposed investment became part of our IT Capital Plan and the associated Roadmap.

All investments approved through the business justification process were entered into United Energy's IT Capital Expenditure Cost Model. The model's primary function is to model the forecast capital expenditure of a number of projects across the 5 year IT Capital Program period. It provides the ability to:

- Calculate capital expenditure for each project using standard "Unit Costs" e.g. Labour rates that apply across every project;
- Enter proposed start and end dates for each project;
- Enter a labour effort profile (labour type and burn rate) across the duration of the project;
- Calculate hardware and software costs for each project based on default percentages (which can be over ridden where costs are known or expected to differ from defaults);
- Calculate "Project Costs" to determine the expenditure forecast for project-related components of its capital expenditure forecasts (e.g. Security and Project Management Office Costs); and
- Provide both Calendar Year (CY) and Financial Year (FY) views of the capital expenditure.

C3: Project Estimating

Wherever possible cost estimates were based on our experience of actual costs of a similar previous project. We have carried our many systems upgrades. The actual costs of these upgrades in the current period provided an accurate basis for estimating the costs of further upgrades in the forthcoming period. Information on recent actual costs were supplemented and verified by vendor quotes and market data if available.

Project expenditure is allocated over time in the cost model according to the timing and duration of each project.

Detailed forecast project costs are composed of:

- **Labour costs**: resources (FTEs) required for project delivery for example: IT consultants, Developers, Testers, procurement and business subject matter experts (SME). Labour rates are largely based on the rates defined in master services agreements (MSAs) with the panel of specialist project integration companies. These MSAs include daily rates for the provision of both on and off-shore resources for ad-hoc project work. The model applies the average of the contracted MSA rates with each of the two major service providers. Labour rates are itemised and applied within the cost model;

- **Software costs**: purchase and licensing costs according to the specific requirements of each project. Software costs estimates are based on information from software vendors; and
- **Hardware costs**: Specific hardware required for application projects for development, testing, production, Disaster Recovery and on-going production support. With most environments now being virtual, infrastructure can be “spun up” for development and returned post deployment so these costs are taken into account accordingly. If new hardware is required, costs are estimated based on information from software vendors.

In some cases, a ‘cloud’ or ‘software-as-a-service’ solution may be a cost-effective approach to meeting a requirement. In these case, estimates are largely based on information from suppliers.

C4: Allocation between SCS and ACS - metering

Our IT systems are used for both the provision of SCS and ACS. Where systems are solely dedicated to either SCS or ACS, capital costs for new, replacement or upgraded systems are assigned accordingly. The most significant ACS, in terms of IT expenditure, is metering. The cost allocation approach is as follows:

- If a system is required to meet our obligations for SCS, then the costs of upgrading and refreshing that system will be largely allocated to SCS. This allocation is on the basis that we will continue to require the system and would incur the costs even if we were no longer providing the metering ACS. As an example, the system which we use for the management of interval meter data (Itron IEE) is required for the provision of SCS. The costs of implementing new releases to Itron are therefore be allocated to SCS;
- IT capital costs will be allocated to metering ACS where those costs are incurred specifically to meet specific ACS - metering requirements. For example, the introduction of metering contestability and other metering requirements will require that specific changes are made to Itron IEE. In those cases, costs would be allocated to ACS – metering; and
- Where systems are largely used for metering but deliver significant SCS functions, costs are allocated across both metering ACS and SCS. For example, the costs of upgrading our meter management system (SSN UIQ) are allocated across metering ACS (60%) and SCS (40%).

A similar approach has been adopted for allocation of operating costs.

C5: Opex impacts of IT Capital Projects

Every capital project has a potential impact on both business and IT operating costs. Every project justification has considered and captured the forecast operating cost impacts which have then been taken into account in the relevant Operating Cost (OPEX) budgets. Any increases in base year opex have been itemised in the Regulatory Submission document and in the Opex Overview document.

The IT Operating costs consider and reflect the following:

- Hardware support and maintenance (including infrastructure support provided by UE’s service provider);
- Software support and maintenance;
- Application support (as provided by UE’s Applications service provider);
- Cloud Service fees as appropriate; and
- Cost reductions arising from decommissioning of hardware and/or software.